WildEarth Guardians
A FORCE FOR NATURE

August 3, 2026

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Oil Conservation Commission
New Mexico Energy, Minerals, and Natural Resources Dept.
1220 S. St. Francis Drive
Santa Fe, NM 87505

OCC No. 25875

Submitted via email: occ.hearings@emnrd.nm.gov

WildEarth Guardians' Comments on the New Mexico Class VI Proposed Rules

WildEarth Guardians (Guardians) provides these comments on the Oil Conservation Division's (OCD's) proposed rules for Class VI primacy for the record in **OCC No. 25875**. Guardians also incorporates by reference the September 26, 2025 Conservation Groups comments, to which Guardians is also a signatory (attached as Exhibit 1). For the reasons discussed below, Guardians urges the Oil Conservation Commission (OCC) to reject the proposed regulatory scheme.

OCD Has Not Demonstrated a Need for Primacy Beyond Fast-Tracking Permitting

As OCD states in its Petition for Rulemaking, it's seeking to assume primary responsibility for the permitting, compliance, and enforcement of Class VI carbon capture and storage (CCS) injection wells to fast track the permitting of these wells - reducing the permitting time from EPA's 3-6 years to 6-8 months at the state level. The reason OCD give in its Petition for needing to fast-track the Class VI permitting process is "bringing the State closer to achieving its waste mitigation and climate goals." OCD's petition also states a need to "enhance both regulatory efficiency and environmental stewardship." Yet nowhere in OCD's materials submitted for this hearing does the Division explain the specific "waste mitigation and climate goals" the proposed regulatory scheme is intended to achieve or how having primacy over the Class VI permitting process will achieve these undefined goals, or enhance environmental stewardship.

In fact, CCS is not a climate solution. While CCS is often touted as a mitigation measure for the climate crisis, it actually has the potential to increase greenhouse gas emissions by prolonging fossil fuel extraction. The Intergovernmental Panel on Climate Change's (IPCC) modeled pathway with the best chance of keeping warming below 1.5°C makes **no** use of fossil fuels with CCS, and employs limited to zero use of engineered carbon removal technologies.[1] Instead, the

[1] **Exhibit 2**. Ctr. for Int'l Envtl. L., *Confronting the Myth of Carbon-Free Fossil Fuels: Why Carbon Capture Is Not a Climate Solution*, at 2 (2021), https://www.ciel.org/wp-content/uploads/2021/07/Confronting-the-Myth-of-Carbon-Free-Fossil-Fuels.pdf (citing Intergovernmental Panel on Climate Change, *Summary for Policymakers*, in

success of achieving that warming reduction pathway requires a rapid phaseout of fossil fuels along with only limited CO_2 removal by natural carbon sequestration methods, such as reforestation and enhanced soil remediation.[2] Because CCS is unnecessary, ineffective, dangerous, and will actually delay reaching greenhouse gas reduction target, CCS is not a climate solution that will prevent the worsening harms of the climate crisis, and new CCS infrastructure (such as Class VI wells) is contrary to the public interest.

Even if fast-tracking Class VI permitting in the name of "regulatory efficiency" was a legitimate justification for seeking primacy (which it is not), OCD has demonstrated a need for regulatory efficiency as more protective of underground sources of drinking water and public health than EPA's Class VI permitting process. For New Mexico, EPA estimates 1-3 Class VI projects based on EPA's engagement with potential Class VI permittees.[3] And EPA is undergoing its own process to streamline its own Class VI process for permitting in states such as New Mexico where EPA has implementation authority.[4]

Which begs the question of how a faster approval process for a relatively new, permanent industrial waste disposal method in the state actually benefits people, the environment, and the climate, when weighed against the catastrophic impacts to people and the environment when injection wells fail and release CO_2, as they have in other states. As the pre-filed testimony illustrates, failure of CO_2 injection wells has led to asphyxiation deaths and long-term groundwater contamination. And injection-induced seismicity has resulted in earthquakes which caused personal injuries and property damage.[5] Unless and until OCD can articulate how state primacy over the Class VI program will benefit New Mexicans in light of these serious potential risks, the Commission should not allow OCD to move forward with its primacy application.

OCD Lacks Capacity to Oversee and Enforce the Proposed Class VI Regulatory Scheme

In its pre-filed and live technical testimony, OCD consistently stresses the need for speed in processing and approving Class VI permits, with little evidence demonstrating that OCD has the staffing and funding capacity to ensure that its permanent underground waste disposal program will protect groundwater, communities, and future generations from long-term contamination risks. Class VI permitting is complicated and highly technical, as reflected in the proposed regulatory scheme, and EPA's own words to Congress: "[Geologic storage] is a complex process that is highly dependent on site-specific conditions; therefore, a robust and comprehensive permit application and permit review process is fundamental to preventing endangerment of [underground sources of drinking water] from these activities."[6] With fewer resources and less experience than the EPA—in addition to a long history of cooperation with

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Global Warming of 1.5°C, at 14 (Masson-Delmotte et al. eds., 2018), Section C.1.1., Figure SPM 3b (Pathway 1), https://www.ipcc.ch/sr15/)

[2] *Id*. at 2-3. *See also* **Exhibit 3**. September 26, 2025 Center for Biological Diversity Comments on New Mexico Class VI Primacy Draft Rules, at 1-2.

[3] **Exhibit 4**. EPA, "Report to Congress Regarding Recommendations to Improve Class VI Permitting Procedures for Commercial and Research Carbon Sequestration Projects," at 16 (Oct. 28, 2022). https://www.epa.gov/system/files/documents/2022-11/EPA%20Class%20VI%20Permitting%20Report%20to%20Congress.pdf

[4] *Id*. at 20.

[5] Direct Testimony of Dr. Catherine Helm-Clark. Center for Biological Diversity Exhibit 3 at pp. 0048-53.

[6] *Supra*, n.3., at 19.

New Mexico industry—it is unlikely that OCD will be able to provide as robust a review of forthcoming Class VI permit applications as EPA has historically done.

OCD states that a fully-staffed Class VI program will consist of three (3) full-time staff. OCD will also rely on geologists, engineers, field inspectors, and specialized technical contractors for technical expertise to support the Class VI program. Yet OCD has not provided any discussion regarding the number of Class VI permits the 3-person staff will be required to process, the number of wells associated with each permit once projects are built out that will require oversight and enforcement by the Division, workload allocation between permit approvals and oversight and enforcement, or whether the small in-house team is an adequate staff size to ensure both rigorous permit review and comprehensive post-permit oversight and enforcement.

In addition to concerns about staffing levels for the Class VI program, particularly capacity for oversight and enforcement once permits are issued, Guardians also has serious concerns with the tentative nature of the funding for the Class VI program beyond the few full-time program staff funded by the State's general fund. Given OCD's expected reliance on specialized technical contractors to review permit applications, and to perform field inspections to ensure compliance with construction and operational requirements and ensure the safety of those operations, the lack of any funding contingency plans or firm commitments by OCD that any funding shortfalls will **not** result in program staff time being limited to permit approvals at the expense of permit oversight and enforcement should give OCC pause in approving the proposed regulatory scheme.

OCD's Demonstrated Lack of Capacity to Oversee and Enforce Its Existing Programs

OCD has a demonstrated lack of capacity to oversee the programs it already administers to regulate the oil and gas industry, including the Class II UIC program. In the Ground Water Protection Council's 2020 Peer Review of New Mexico's Class II UIC Program, the Council reported:

> The OCD projects that its workload will continue to increase in the foreseeable future as a result of Permian production . . . Despite this vastly increased workload, staffing within OCD has not increased as a result of an inability to expand staffing levels, recruit new staff to replace departing staff due to salary constraints, and retain existing staff because of budget limitations. These three conditions have resulted in staffing shortages of between 40-60 percent in some sections and have placed the OCD in a near crisis situation from a programmatic standpoint. At present, the OCD has insufficient staff available to manage critical aspects of a Class II UIC program such as witnessing of Mechanical Integrity Tests (MITs) and casing installation and cementing, conducting periodic file reviews and implementing inspection frequencies at levels that would guarantee protection of Underground Sources of Drinking Water (USDWs). Even if staffing were filled at the current fully authorized levels the program would still be unable to meet all of the needs for USDW protection contemplated in the states' primacy agreement with the [EPA].[7]

[7] **Exhibit 5**. Ground Water Prot. Council, "State of New Mexico Class II UIC Program Peer Review" (Jan. 8, 2020), at 4, https://www.gwpc.org/wp-content/uploads/2019/09/New_Mexico_Peer_Review_1_8_2020.pdf.

The report goes on to state, "OCD has been unable to increase its budget to provide for elevated staffing levels and has also been unable to reclassify positions to make state service more attractive to those with the qualifications needed to implement a Class II UIC regulatory program."[8] These concerns are reflected in OCD's enforcement efforts today,[9] as it continues to cite a lack of capacity in its struggle to enforce other programs it administers and there is no reason to believe that OCD will be better resourced to manage administration of Class VI wells.

Oil and gas extraction in New Mexico is characterized by thousands of spills, recurring pollution, and limited enforcement. For overall spill trends, industry reported spill data from OCD over the last several years reported a total of 38,153 spills in New Mexico in 2025[10] – an average of 104 spills per day – reflecting an immense amount of pollution to air, land, and water. The 2025 trend in spill scale and frequency is not a one-off anomaly. Between 2022 and 2025, oil and gas operators reported 177,704 spills to OCD.[11]

For 2026, a Waste Watch analysis from WildEarth Guardians documented 17,373 reported oil and gas spills during the first half of 2026—an average of 96 spills every day, or roughly one reported spill every 15 minutes.[12] Operators reported spilling more than 4.5 million gallons of liquid oil and gas waste in the first six months of the year, with more than 1.5 million gallons permanently "lost" to New Mexico's soil and water. The analysis also found that enforcement remains limited despite tens of thousands of reported spills each year.

Despite tens of thousands of oil and gas spills reported each year, enforcement remains limited relative to the scale of pollution. The same companies repeatedly rank among the top spillers, while penalties remain rare. OCD's Spill Search database shows the seven companies are responsible for 50 percent of total oil and gas-related spills between 2022 and 2025.[13] These repeat offenders include EOG Resources, XTO Energy, Matador Production, Earthstone Operating, and Devon Energy Production.[14] Yet OCD continues to issue oil and gas extraction permits to these repeat offenders without follow-up oversight or enforcement actions to prevent continuous spilling of toxic fracking waste.

OCD has the authority to enforce the Oil and Gas Act and hold repeat offenders accountable for polluting New Mexico's air and water with their toxic fracking waste. In 2020, OCD regained authority to assess civil penalties for violations of the Oil and Gas Act following updates to its enforcement rules. NMSA § 1978, § 70-2-31(B). In 2021, the OCC adopted a rule that explicitly prohibited liquid oil and gas spills, including releases of oil, chemicals, and

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[8] *Id*.

[9] For example, OCD's online spills database shows that one operator - OXY USA - reported 33 spills from salt water disposal injection well facilities, four of which are from 2026 alone.

[10] **Exhibit 6**. Melissa Troutman and Rebecca Sobel, WildEarth Guardians, *The 2025 New Mexico Oil & Gas Spill Report: Land, Air & Water Pollution from Oil and Gas* (2026) at 11, https://wildearthguardians.org/press-releases/record-volumes-of-oil-and-gas-spills-polluted-new-mexico-in-2025-new-report-finds/.

[11] *Id*. at 11.

[12] **Exhibit 7**. https://wildearthguardians.org/press-releases/q2-waste-watch-new-mexico-oil-and-gas-spill-counts-drop-but-toxic-waste-volumes-surge/

[13] New Mexico Oil Conservation Division Spill Search, queried January 5, 2026 for all spills reported between January 1, 2022 and December 31, 2025: https://wwwapps.emnrd.nm.gov/ocd/ocdpermitting/data/spills/Spills.aspx.

[14] *Supra*, n.10, at 11.

produced water. 19.15.5.10(D) NMAC. This regulatory update was intended to strengthen spill prevention and cleanup authority. At the time, the Energy, Minerals and Natural Resources Department (EMNRD) described the rule change as providing OCD with additional tools to prevent and remediate spills in the oil and gas field.[15]

Together, these actions restored and expanded the state's legal authority to penalize spill-related violations and require cleanup. Yet publicly available records show that enforcement has not been applied at a scale commensurate with the volume and frequency of reported spills. From 2021 to 2025, OCD issued only a small number of civil penalties, despite tens of thousands of reported spills and clear evidence that the same operators repeatedly rank among the top polluters quarter after quarter.[16]

Absent consistent enforcement, the spill problem is likely to intensify as wells age and extraction declines. State regulations specify cleanup requirements and the substances that must be addressed when contamination occurs.[17] Despite these requirements, cleanup obligations are not absolute. When an operator asserts that meeting cleanup standards is "technically infeasible" or would impose an "unreasonable burden," the company may petition the OCD for an alternative abatement standard. If approved, this allows reduced cleanup requirements and permits some contamination to remain in place, subject to conditions set by the Division.[18] These provisions create a regulatory pathway for pollution to persist in the environment, particularly where contamination is difficult to locate, expensive to remediate, or challenging to verify. Over time, the cumulative effect of incomplete cleanup, undocumented contaminants, and repeated spills compounds risks to land, water, air quality, and public health, while shifting long-term burdens away from polluters and onto taxpayers and communities.

OCD's primacy over the Class VI permitting process will only exacerbate the existing pollution and contamination problems caused by oil and gas extraction. During the rulemaking hearing, OCD reported that the Division currently has only 18 field inspectors to oversee tens of thousands of producing and non-producing oil and gas wells. Currently, two of these inspectors are assigned to inspect injection wells in southeastern New Mexico. The remaining inspectors are responsible for all other field inspections spread across **all** of OCD's programs. During the hearing, OCD also stated that in order to maintain the Class VI program, if needed it would shift some of these field inspectors to the Class VI program. This will ensure that OCD is always chronically behind with well inspections to prevent spills and enforce spill clean-up requirements.

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[15] New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Commission Spill Rule Hearing and Rule Release, July 8, 2021, quoting EMNRD Cabinet Secretary Sarah Cottrell Propst: "Finalization of the release rules are another example of this administration's commitment to collaboration and protecting the environment… Now that the updated release rules are in effect, the OCD will have additional tools to prevent and remediate spills that occur in the oil and gas field," https://www.emnrd.nm.gov/officeofsecretary/wp-content/uploads/sites/2/OCDSpillRuleHearingRuleRelease070821.pdf.

[16] WildEarth Guardians, Oil & Gas Waste Watch Reports, Q1–Q3 2025 analyzing publicly available spill data at https://wildearthguardians.org/climate-health/oil-gas-waste/; public information request and review of publicly available OCD enforcement actions and press releases (2021–2025); OCD compliance activity available at https://www.emnrd.nm.gov/ocd/compliance/. *See also*, *supra*, n.10, at 28.

[17] NMSA 1978, § 74-6-4; 20.6.4 NMAC; 20.6.2 NMAC.

[18] 19.15.30.9 NMAC.

Before OCD rushes to take on responsibility for permanently storing industrial carbon waste underground through a new regulatory program, it needs to first demonstrate to New Mexicans and the Commission that it can effectively oversee the oil and gas waste system it already regulates. Unless and until OCD does this and reverses its failing track record on oversight and enforcement, the Commission cannot allow the Division to take on yet another regulatory program that it's unable to manage, oversee, and enforce.

Conclusion

OCD's status quo of lax regulations and inadequate enforcement of its current regulatory programs has allowed the oil and gas industry to run rampant, wreaking havoc on our land, water, and communities. With record emissions and daily toxic waste spills, OCD needs to prioritize strengthening oversight for the programs it currently administers before taking on primary responsibility for a new regulatory program. Doing so will ensure that oil and gas extraction doesn't sacrifice public health and clean water.

Sincerely,

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TABLE OF EXHIBITS

Exhibit No.	Description/Title
1	September 26, 2025 Conservation Groups Public Comment on Class VI Primacy Draft Rules
2	Ctr. for Int'l Envtl. L., *Confronting the Myth of Carbon-Free Fossil Fuels: Why Carbon Capture Is Not a Climate Solution* (2021)

3	September 26, 2025 Center for Biological Diversity Comments on New Mexico Class VI Primacy Draft Rules
4	EPA, *Report to Congress Regarding Recommendations to Improve Class VI Permitting Procedures for Commercial and Research Carbon Sequestration Projects* (Oct. 28, 2022). [Excerpts]
5	Ground Water Prot. Council, *State of New Mexico Class II UIC Program Peer Review* (Jan. 8, 2020). [Excerpts]
6	Melissa Troutman and Rebecca Sobel, WildEarth Guardians, *The 2025 New Mexico Oil & Gas Spill Report: Land, Air & Water Pollution from Oil and Gas* (2026)
7	WildEarth Guardians, "Q2 Waste Watch: New Mexico Oil and Gas Spill Counts Drop, but Toxic Waste Volumes Surge," (July 14, 2026).

WildEarth Guardians

Exhibit 1

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WESTERN ENVIRONMENTAL LAW CENTER

September 26, 2025

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Re: Public Comment on Class VI Primacy Draft Rules

Dear Mr. Bajema,

350 Santa Fe Inc., Conservation Voters New Mexico Education Fund, Diné C.A.R.E., Earthworks, GreenLatinos New Mexico, San Juan Citizens Alliance, Sierra Club Rio Grande Chapter, Tó Nizhóní Ání, Western Environmental Law Center, and WildEarth Guardians (Conservation Groups), respectfully submit the following comments on and recommendations for the Oil Conservation Division's (OCD) draft rules for Class VI Primacy, which are based on federal requirements found in 40 C.F.R. Parts 124, 144, and 146. While Conservation Groups appreciate places where the draft rules are more stringent at the federal level, we urge OCD to address the issues raised below in its next round of revisions.

GENERAL CONCERNS

Community Engagement and Environmental Justice:

Former EPA guidance encouraged states to consider environmental justice impacts as part of their Class VI programs, encouraging states to "evaluate whether the siting of a Class VI project at the proposed location will create any new risks or exacerbate any existing impacts on lower-income people and communities of color[,]" as "[s]uch evaluations might consider the presence of existing environmental hazards, potential exposure pathways, and susceptible sub-populations, as well as the likely distribution of any environmental and public health benefits from the proposed Class VI project in affected communities."[1] Several states demonstrate viable approaches to the consideration of environmental justice:

West Virginia's Class VI Primacy Application included a memorandum of agreement outlining various measures the state would take to provide heightened protections for environmental justice communities, including conducting an environmental assessment screening of every Class VI well application received, requiring heightened participation requirements for areas of concern, hosting at least one annual community meeting throughout the lifetime of the project, and performing a cumulative impact analysis.[2] Importantly, West Virginia was granted primacy under the current administration, demonstrating that these extra measures can pass scrutiny by EPA.[3]

Louisiana requires an environmental justice review requirement for permit applicants, in which a prospective owner or operator must present an environmental justice review that includes "a weighing of siting, environmental effects, and a cost benefit analysis."[4] The results of the review determine whether an "enhanced" public comment procedure should be required for the permit application.[5] Although Louisiana was granted primacy before the change in the federal administration, a substantively similar review could be included in New Mexico without the phrase "environmental justice."

Colorado calls for a determination that new wells will not have negative net cumulative impacts on disproportionately impacted communities. The state requires the agency to "weigh the potential adverse and beneficial impacts to public health and the environment of the proposed Class VI Development Plan, including any related mitigation projects and community benefit agreements, on the [DI] Community" when making a permitting decision.[6] If the ECMC finds that the project would have negative net cumulative impacts on the community, the ECMC must deny the developer's application.[7]

As the federal government rolls back its commitment to environmental justice and mitigating environmental impacts on overburdened communities, New Mexico should step up to ensure environmental justice is incorporated in its Class VI permitting program. Incorporating guardrails from the 2022 E.P.A. letter to governors, as well from as the regulatory schemes in West Virginia, Louisiana, and Colorado—such as the requirement of an environmental justice screen and the cumulative impact analysis for areas identified in the screening process—is necessary to mitigate the harms associated with new infrastructure in communities already overburdened by development.

Siting Requirements: The draft rules' siting requirements (located at Reserve3(B)D.(1)) currently require consideration of the suitability of the geologic system. The draft rules should be

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[1] Michael S. Regan, Environmental Protection Agency, (Dec. 9, 2022), accessible at https://www.regulations.gov/document/EPA-HQ-OW-2023-0073-0004.
[2] *Memorandum of Agreement Amended Addendum 1,* West Virginia D.E.P. and U.S. E.P.A. Region 3 (2024), accessible at https://www.regulations.gov/document/EPA-HQ-OW-2024-0357-0002.
[3] U.S. E.P.A,, *Administrator Zeldin Approves West Virginia's Class VI Primacy Application* (Feb. 18, 2025), https://www.epa.gov/newsreleases/administrator-zeldin-approves-west-virginias-class-vi-primacy-application.
[4] *See* Louisiana Department of Natural Resources, Office of Conservation, *Comparison of Federal and Louisiana Regulations for Class VI Injection Wells*, https://www.dnr.louisiana.gov/assets/OC/ClassVI/Overview/FederalandLAClassVIDifferences_Jan2023.pdf.
[5] *Id.*
[6] 2 COLO. CODE REGS. § 404-1-1410(d).
[7] *Id.*

amended to incorporate consideration of surface infrastructure—in particular, the presence of residential buildings, high occupancy buildings, schools, or childcare centers. Colorado, for example, prohibits Class VI wells from being located within 2,000 feet of a home, school, or commercial building—with no exceptions.[8] We recommend that OCD incorporate a requirement that these projects be set back from such buildings.

Consideration of Human Health, Safety, and the Environment: Wyoming strengthened the regulations by adding a requirement of consideration of potential endangerments to "human health, safety, or the environment" at various stages during the permitting process.[9] We encourage OCD to do the same.

Storage Fund Fees: H.B. 458 ('25) established the Geologic Carbon Dioxide Long-Term Storage Fund, a non-reverting fund in the state treasury consisting of fees collected from each operator for each ton of carbon dioxide (CO_2) injected. Although OCD has represented publicly that it is limiting this rulemaking to the scope of what is required for obtaining primacy,[10] we are concerned that decoupling this portion of the Class VI regulatory regime from the imminent rulemaking will cause unnecessary delay in its implementation. We encourage OCD to include the tonnage fees in this rulemaking, and to set the tonnage fees in the range of $0.31-0.62.[11]

Raw Operating Data: OCD should require the periodic provision of raw monitoring data, as required in Louisiana.[12]

OCD Staffing and Expertise: We have two pieces of feedback on this subject:

First, both Louisiana requires project review by engineers or geoscientists.[13] We propose that OCD require the same.

Second, Colorado's proposed rules include requirements for prospective well owners or operators to engage community representatives known as "community liaisons," throughout the permit application process.[14]

Class II to Class VI Transition: In addition to specific proposals for Class II to Class VI transition below at **Reserve2(B)E.(1)**, we emphasize that:

(1) OCD should develop additional requirements around the transition process, including adequate construction standards for wells (including both Class II and Class V wells)

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[8] Ed Sealover, *Business Leaders Deflated By Preliminary State Rules on Carbon Management*, SUM & SUBSTANCE (Dec. 5, 2024).

[9] *See, e.g.,* Wyo. Admin. Code 020.0011.24 §§ 7(a)(iii) (determining threatening activity warranting permit termination), 13(b)(i)(B) (determining threat from pressure differentials to inform delineation of Area of Review), 25(a) (describing requirements for emergency and remedial response plan).

[10] *See* EMNRD presentation to the Radioactive & Hazardous Materials Committee on Sept. 2, 2026.

[11] *See* Il. S.B. 1289 (2024).

[12] *See* Louisiana Department of Natural Resources, Office of Conservation, *Comparison of Federal and Louisiana Regulations for Class VI Injection Wells*, https://www.dnr.louisiana.gov/assets/OC/ClassVI/Overview/FederalandLAClassVIDifferences_Jan2023.pdf, (requiring the provision of "the raw operating data from the continuous recording devices prescribed by §3621.A.6 submitted in digital format").

[13] *See id.*

[14] 2 COLO. CODE REGS § 404-1:224.

likely or planned to convert to Class VI wells, and adequate mechanisms for public notice for transition of Class II wells to Class VI wells.

(2) Requirements for Class II wells should be heightened, as Class II wells carry many of the same risks as Class VI wells. Specifically, Class II wells should be required to adhere to requirements around stakeholder engagement, emergency response, financial responsibility, plume monitoring and modeling, post-injection site care and closure requirements, to ensure safe operation. We encourage OCD to initiate a rulemaking in the near future to address gaps in the Class II regulations.

Monitoring Wells: The draft rules discuss reporting of the presence or addition of monitoring wells, but lack clear guidance on the siting, construction, integrity, and operation of those wells (e.g. selection and use of appropriately compatible materials). Both injection *and monitoring* wells must be designed for the type of CO_2 they will encounter (e.g. CO_2-saturated brine v. dry CO_2 injection), as injection wells penetrate the storage formation and therefore represent potential leakage pathways and require monitoring and reporting on their effective operation. Additionally, the rules should require the prompt plugging of monitoring wells immediately after data show the plume has arrived at the well, to prevent the monitoring well from becoming a potential leakage pathway (notably, once plume arrives at monitoring well, it no longer serves a useful function in tracking the CO_2 plume).

RESERVE 1 (PART 124)

Reserve1C.(1): Modification, revocation and reissuance, or termination of permits (Line 4 in Crosswalk): The draft rule text does not appear to be equivalent to, let alone more stringent than, the federal text. Most significantly, it fails to provide an avenue for "any interested person" to request the modification, revocation, reissuance, or termination of a permit. The draft rule must be amended to restore this provision.

Reserve1F.(3): (Crosswalk Line 31): This provision requires that the public be given 30 days for public comment on a draft permit application. This period should be extended to 60 days, as in Colorado.[15] OCD should also consider holding a public hearing for all Class VI permits, as in Colorado.[16]

RESERVE2 (PART 144)

Reserve2(A)B.(20): "Generator" (Crosswalk Line 89): It is unclear where OCD draws authority to regulate carbon dioxide (CO_2) generated from activities other than oil and gas operations. *See* NMSA § 70-2-6(A) (providing general authority over matters relating to the conservation of oil and gas).

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[15] 2 COLO. CODE REGS § 404-1-1406(2)(A); *see also* WHITE HOUSE ENV'T JUSTICE ADVISORY COUNCIL, WHITE HOUSE ENVIRONMENTAL JUSTICE ADVISORY COUNCIL RECOMMENDATIONS: CARBON MANAGEMENT 27 (Oct. 4, 2024).

[16] 2 COLO. CODE REGS § 404-1-1405(g).

Reserve2(A)B.(21): "Geologic Sequestration" (Crosswalk Line 90): The proposed rule defines "geologic sequestration" as the "*long-term* containment of…carbon dioxide." The OCD should consider replacing "long-term" with "permanent."

Reserve2(B)B.(1)-(2): Prohibition of movement of fluid into underground sources of drinking water (Crosswalk Line 161): These provisions prohibit owners or operators from conducting injection activities in a manner that allows the movement of contaminating fluid into underground sources of drinking water (USDWs), and requires that the Director prescribe additional requirements if monitoring shows the movement of contaminants into the underground source of drinking water. In both these provisions and elsewhere, the rule is framed around a USDW being affected, rather than the potential for it to be affected. OCD should consider amending key portions of the rule to clarify that the rules address the *potential* for impact, rather than actual contamination.

Reserve2(B)E.(1): Transitioning from Class II to Class VI (Crosswalk Line 166): Like Class VI wells, Class II wells can be used for long-term CO_2 sequestration when used for enhanced oil recovery (EOR). However, Class II wells lack the significant guardrails and requirements associated with Class VI and commensurate with the risk associated with long term CO_2 storage. When the EPA first announced the Class VI rules, it justified the difference between CO_2 EOR in Class II and storage in Class VI on the grounds that Class II wells would be handling smaller volumes of CO_2 and would therefore create less risk—despite also acknowledging that the substantial number of well bores in an oil and gas field increase the risk of injected CO_2 leaking through this pathway. At the same time, however, EPA admitted that "if the business model for [EOR] changes to focus on maximizing CO_2 injection volumes and permanent storage, then the risk of endangerment to [underground sources of drinking water (USDWs)] is likely to increase and such wells may need to be re-permitted as Class VI wells."[17] Due to recent changes in the 45Q federal tax credit, it is likely there will be a significant increase in the practice of using CO_2 for EOR. In anticipation of this increase, New Mexico should resolve ambiguities that remain in the underground injection control program when deciding whether a Class II well needs to transition to a Class VI well, specifically by amending this provision. Currently, it mirrors the federal rules, to require that owners or operators of Class II wells injecting CO_2 for the "primary purpose of long-term storage… must apply for and obtain a Class VI geologic sequestration permit when there is an increased risk to USDWs compared to Class II operations." The process for this transition is murky—it is not clear when the review process is triggered, how to define "primary purpose," or how to properly evaluate the factors in determining whether an increased risk to USDW exists. Texas, alternatively, takes a more precautionary approach, requiring that operators transition from Class II to Class VI once EOR is no longer the primary purpose of CO_2 injection, *or* there is an increased risk to USDWs. This approach better addresses the nature of the risks inherent to geologic storage of CO_2, as the risks associated with the injection should alone be a sufficient factor triggering more stringent requirements. Accordingly, we encourage OCD to amend this provision of the rule to read: "Owners or operators that are injecting carbon dioxide for the primary purpose of long-term storage into an oil and gas reservoir or there is an

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[17] United States Environmental Protection Agency, *Draft Underground Injection Control (UIC) Program Guidance on Transitioning Class II Wells to Class VI Wells*, Dec. 2013, https://19january2017snapshot.epa.gov/sites/production/files/2015-07/documents/epa816p13004.pdf.

increased risk to USDWs compared to Class II operations must apply for and obtain a Class VI geologic sequestration permit. In determining if there is an increased risk…”

Reserve2(B)E.(2)(b): Increase in carbon dioxide injection rates (Crosswalk Line 169): The proposed rule does not specify what increase in carbon dioxide injection rates would warrant conversion to a Class VI permit. We request that OCD establish in the proposed rule clear numeric thresholds of injection volumes that would require an operator to obtain a Class VI permit.

Reserve2(B)E.(2)(c): Decrease in reservoir production rates (Crosswalk Line 170): As with carbon dioxide injection rates, we request that OCD establish clear numeric thresholds of reservoir production rates that would require an operator to obtain a Class VI permit.

Reserve2(D)A.(5)(h): Names and Addresses of Property Owners (Crosswalk Line 200): This provision refers to the names and addresses of nearby property owners that must be included in an application for a Class VI permit. We applaud OCD for removing the federal provision that allows for a waiver of this requirement in populous areas.

Reserve.XXXX.NMAC: Area Permits (Crosswalk Line 211): We have three pieces of feedback on these provisions:

First, the text provided in the crosswalk does not appear to be in the draft rules.

Second, the rules must account for interwellbore interference–whether in area permits or between separate individual Class VI wells. Multiple injection sites located proximate to one another can *multiply* the rate of pressure increase, implicating more leakage pathways than would have been identified in the Area of Review for each individual injection site.[18] The EPA anticipated when it established the Class VI well category that Class VI programs would need to account for “interactions between previously injected CO_2 and other fluids, and an increase in reservoir pressure as a result of multiple injectors and subsurface plume interaction.”[19] The cumulative nature of multiple injection projects should be accounted for in any area permits.

Third, Louisiana does not allow area permits. We recommend that OCD amend the rules to prohibit area permits as well, given the concerns with interwellbore interference outlined supra at Crosswalk 211.[20]

Reserve2(D)D.(1): Duration of Permits (Crosswalk Line 215): The draft rules specify that Class VI permits shall be reviewed by the Commissioner no less frequently than every five years. We request that this interval be reduced, particularly in the first few years as injection operations begin. We encourage OCD to require an initial review at one year after injection activities commence, and every two years thereafter during a project’s operation.

[18] *See* Susan D. Hovorka & Alexander P. Bump, White Paper: Addressing Multiple Uses of the Subsurface: Allocating Pressure Space 23 (2024), https://www.gwpc.org/wp-content/uploads/2025/05/Pressure-interference-white-paper-updated-12-6-24.pdf.

[19] 75 Fed. Reg. at 77,256.

[20] Louisiana Department of Natural Resources, Office of Conservation, *Comparison of Federal and Louisiana Regulations for Class VI Injection Wells*, https://www.dnr.louisiana.gov/assets/OC/ClassVI/Overview/FederalandLAClassVIDifferences_Jan2023.pdf.

Reserve2(D)E.(1): Continuation of Permits (Crosswalk Line 218): The federal regulations specify that the conditions of an expired permit may continue in force until the date of the new permit if two conditions are met: (1) the permittee has submitted a timely and complete application for a new permit, *and* (2) through no fault of the permittee, the Regional Administrator does not issue a new permit with an effective date on or before the expiration date of the previous permit. In contrast, the draft rules for New Mexico specify that the conditions of an expired permit may continue in force if *either* of these conditions are met. The way this provision is currently drafted is less stringent than federal regulations.

Reserve2(D)F.(2): Automatic Transfers (Crosswalk Line 225): We appreciate OCD prohibiting automatic transfers unless approved by the Director. It is unclear, however, how a transfer would be automatic if it requires approval by Director. Accordingly, we encourage OCD to prohibit automatic transfers altogether.

Reserve2(D)G.(1)(b): Information (Crosswalk Line 229): As in the federal regulations, the draft rules provide that new information may be cause for modification or revocation of a permit. For UIC area permits, this includes information indicating that cumulative effects on the environment are unacceptable. As discussed supra at Crosswalk Line 211, multiple individual wells can have cumulative effects much greater than each individual well. OCD should consider extending this provision beyond area permits to regular Class VI permits.

RESERVE3 (PART 146)

Reserve3(A)B.(1)(b)(ii): (Crosswalk Line 367): This provision specifies that an aquifer can be eligible for exemption for Class VI wells if an aquifer cannot in the future become a source of drinking water because "[i]t is situated at a depth or location which makes recovery of water for drinking water purposes economically or technologically impractical." This provision should be removed, as future technology may make presently inaccessible aquifers viable. Colorado's rules, for example, include fewer criteria for determining which aquifers may be unusable as sources of drinking water in the future.[21]

Reserve3(B)E.(3): (Crosswalk Lines 450-456): These provisions describe the prediction of an area of review, but fail to specify a minimum delineated area. Risk of leakage extends beyond the leakage plume to the edge of the pressure front, which can be 10 to 100 times further from the wellbore than the CO_2 plume itself.[22] We encourage OCD to adopt a minimum Area of Review of ¼ mile from the project site.

Reserve3(B)C.(1)(b): (Crosswalk Line 394): This provision requires project proponents to submit with their application a map of all abandoned wells within the area of review. As it is likely that injection projects will occur in areas with historic drilling, however, and undocumented abandoned wells may exist within the Area of Review, OCD should require instrumented undocumented abandoned well surveys within any area with historic drilling.

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[21] 2 COLO. CODE REGS § 404-1-1402.
[22] Ringrose, P.S. & Meckel, T.A., *Maturing global CO_2 storage resources on offshore continental margins to achieve 2DS emissions reductions*, Sci Rep 9, 17944 (2019), https://doi.org/10.1038/s41598-019-54363-z.

Reserve3(B)E.(5) Initial AoR Reevaluation (Crosswalk Line 458): We appreciate OCD requiring an initial Area of Review reevaluation in two years, rather than five years as specified in the federal regulations. However, we encourage OCD to require an initial Area of Review reevaluation after the first year, and every two years thereafter.

Reserve3(B)F.(1)(a)(v): Self Insurance (i.e., Financial Test and Corporate Guarantee) (Crosswalk Line 471): This provision must be eliminated entirely from the list of qualifying financial responsibility instruments. "Self-insurance," sometimes referred to as "self-bonding," is a fundamentally flawed approach, as no matter how financially secure a company appears, it can always fail. In 2015-2016, the three largest coal mine operators in the US (Alpha Natural Resources, Arch Coal, and Peabody Energy) went bankrupt. All three had been allowed to self-bond hundreds of millions of dollars in reclamation obligations, and all three had qualified for self-bonding based on their high credit ratings. When the three companies went into bankruptcy, they had enormous leverage over the regulators because there was no bonding in place.[23] Notably, Colorado declined to adopt self-bonding in its primacy rules.[24]

Reserve3(B)F.(1)(a)(vii): Any other instrument(s) satisfactory to the Director (Crosswalk Line 473): OCD should eliminate this provision in its entirety, as the other instruments specified in the draft rule are adequate.

Reserve3(B)F.(1)(d)(i)(A): Cancellation (Crosswalk Line 482): The provisions relating to "cancellation" of financial assurances should also be amended. As written, the rules would allow for cancellation "for failure to pay such financial instrument." This would entirely defeat the purpose of requiring financial assurances. The only circumstance under which cancellation should be possible is if a replacement financial assurance is already in place. Surety providers and other providers of financial assurances assume the risk of operator default. In exchange, they get to collect premiums and secure collateral. Allowing a provider to cancel an instrument for failure to pay defeats the entire purpose. Under that scenario, if an operator were to go out of business and fail to pay to maintain the financial instrument, the provider could cancel the instrument. But that's exactly the time when it's most critical for the financial assurance to be in place. And no other provider is going to be willing to provide a replacement financial assurance at that time, given the operator's failure to pay. At a minimum, the regulations must be amended to specify that in all cases the provider of a financial assurance instrument must be required to provide the Director with notice of its intent to cancel, and the Director must have the ability to forfeit the instrument within the notice period.

Reserve3(B)F.(1)(f)(v): (Crosswalk Line 494): This provision allows an owner, operator, or its guarantor to use self-insurance to demonstrate financial responsibility. As discussed supra at Crosswalk Line 471, this provision should be eliminated.

Reserve3(B)F.(1)(f)(vi): (Crosswalk Line 495): This provision allows an owner or operator not able to meet corporate financial test criteria to arrange a corporate guarantee by demonstrating

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[23] *See* Joshua Macey, Jackson Salovaara, *Bankruptcy As Bailout: Coal Company Insolvency and the Erosion of Federal Law*, 71 Stan. L. Rev. 879, 897-98 (2019) for more discussion on the inherent flaws with self-bonding.
[24] 2 COLO. CODE REGS § 404-1-1415(a)(1).

that its corporate parent meets the financial test requirements on its behalf. For the reasons discussed supra at Crosswalk Line 471, this provision should be eliminated.

Reserve3(B)F.(3): (Crosswalk Line 507): This provision requires that an owner or operator must provide a cost estimate for the costs of performing corrective action on wells in the area of review, plugging the well(s), post-injection site care and site closure, and emergency and remedial response. Although the rules currently provide for new cost estimates to be performed at each phase of the project, Reserve 3.B(F)(3)(a), these requirements could be strengthened. Wyoming, for example, requires that cost estimates be updated annually.[25] Wyoming also requires that the required financial responsibility instruments sufficiently cover the cost of plume stabilization.[26] These provisions demonstrate an effort to better ensure protection for the environment, through requiring the financial ability to respond to any event that might threaten USDWs, public health, or the environment.

Reserve3(B)I.(5): (Crosswalk Line 574): This provision identifies the systems and devices an operator must use to monitor its equipment. In the crosswalk, the federal provision is "[t]he owner or operator must install and use," and the New Mexican provision is "[t]he owner and operator must install, use, and maintain." We support the addition of "maintain," and wanted to flag that it presently does not appear in the copy of the draft rules at Reserve3(B)I.(5).

Reserve3(B)I.(5)(d)-(e): (Crosswalk Line 578): These new provisions specify that "[a]ll alarms shall be integrated with an automated shutdown system to ensure immediate response to critical operating conditions," and that "[t]he operator shall function test all automated emergency shutdown systems at least once every six months." The latter provision does not appear in the crosswalk. We greatly support the addition of these two provisions. We further propose that they be strengthened by adding that operators perform tests on all components of their safety systems twice per year, as required in Louisiana.[27]

Reserve3(B)K.: Testing and Monitoring Requirements (Crosswalk Line 596): This provision specifies that project proponents must provide, as a part of their testing and monitoring plan, a "summary of community engagement activities conducted to develop a plan that addresses project-related risks." The rules should more clearly address how the owner or operator will not just educate the public—as the provision seems to suggest—but take into consideration feedback from the community about how project-related risks can be addressed.

Reserve3(B)K.(6): (Crosswalk Line 607): This provision requires a pressure fall-off test at least once every five years. We recommend that this test should be required *annually* to account for interwellbore interference (discussed supra at Crosswalk 211).

[25] Wyo. Admin. Code 020.0011.24 § 26(b).
[26] *Id.* §26(a)(iv).
[27] *See* Louisiana Department of Natural Resources, Office of Conservation, *Comparison of Federal and Louisiana Regulations for Class VI Injection Wells*, https://www.dnr.louisiana.gov/assets/OC/ClassVI/Overview/FederalandLAClassVIDifferences_Jan2023.pdf.

Reserve3(B)K.(4): (Crosswalk Line 603): This provision requires "quarterly" monitoring of ground water quality, as opposed to the "periodic" monitoring required in the federal regulations. We support this change.

Reserve3(B)K.(7): (Crosswalk Line 608): We want to alert OCD to mismatched semi-colons and periods at the end of each sub provision in this section.

Reserve3(B)K.(7)(c): (Crosswalk Line 611): This provision requires soil gas monitoring to track the extent of the carbon dioxide plume and presence or absence of elevated pressure. We appreciate the requirement of soil gas testing (in the federal regulations, such testing *may* be required by the Director), but suggest that for consistency with other provisions above, the provision be amended to: "Soil gas monitoring to detect…"

Reserve3(B)K.(7)(d): (Crosswalk Line 612): This provision allows the Director to require surface air monitoring to detect the movement of carbon dioxide that could endanger a USDW. We appreciate OCD's acknowledgment of the increased risk of leaking in "oil and gas fields or other areas with a high density of legacy wellbores," but encourage OCD to make surface air monitoring in those environments. To accomplish this, the provision could be amended to read: "Surface air monitoring to detect movement of carbon dioxide that could endanger a USDW in oil and gas fields or other areas with a high density of legacy wellbores, or as required by the Director elsewhere."

Reserve3(B)K.(8): (Crosswalk Lines 616-618): This provision requires seismicity monitoring. We support this addition. However, subsection (a) specifies that design of the seismicity monitoring program must be based on the potential risk of disturbing the confinement efficiency and endangering USDWs. We encourage OCD to pair a new subsection with guidance as described below. A new subsection in the rule should specify that operations must be paused if seismic events are observed several levels below what would risk disturbing the confinement efficiency and endangering USDWs within the Area of Review. OCD should also establish new guidance adopting local magnitude thresholds for different regions in the state based on relevant factors, including geologic considerations, potential hazards to infrastructure or other property, and public safety.

Reserve3(B)K.(10): (Crosswalk Line 620): This provision specifies that the owner or operator must periodically review the testing and monitoring plan. Although we appreciate the new language indicating an initial review should occur after the first two years of injection, and subsequent reviews should occur no less frequently than four years (previously every five years, in the federal regulation), we encourage the OCD to adopt an initial review of the testing and monitoring plan after one year, and periodic reviews every two years thereafter.

Reserve3(B)L.(6): (Crosswalk Lines 649-654): These provisions specify that data and reports for injection wells shall be retained for at least 10 years following site closure. We have two pieces of feedback on these provisions:

First, we don't see a meaningful difference between the federal provision ("for 10 years following site closure") and the New Mexican provision ("for at least 10 years following site closure"), and we therefore don't see this as necessarily more stringent.

Second, due to the eternal nature of these projects and their attendant risks, we believe records should be maintained for far longer—at least 50 years, in line with the default post-injection site care timeframe specified at Reserve 3(B)(N)(2)(a).

Reserve3(B)M.(2): (Crosswalk Lines 659, 662-665): These provisions add various requirements to what must be included in a well plugging plan, including a description of the casing and tubing, pre-closure and post-closure well schematics, and a catch-all provision of "additional information requested by the Director." We support these improvements to the federal regulations.

Reserve3(B)M.(2)(j): (Crosswalk Line 666): This provision specifies that the owner or operator must plug the well upon successful completion of well closure. This provision is critical, and we support its inclusion. However, it does not belong in a list of information that must be provided to the agency. It should more appropriately become a new section after subsection M.(2), displacing current subsection M.(3) (which should then become M.(4), and so on).

Reserve3(B)M.(4): (Crosswalk Lines 668-671): These provisions require information be provided in the well plugging report that is not specified in the federal regulations, and we support the clarity and specificity provided in the sub-provisions. We particularly appreciate the addition of the requirement that a well plugging report clearly identify any deviations from the submitted plan during the closure process.

Reserve3(B)N.(2)(a)-(b): (Crosswalk Lines 683-684): We have two pieces of feedback on these provisions:

First, these provisions specify owners or operators shall continue monitoring *for at least 50 years*, or for the duration of an alternative timeframe approved by the Director. In other words, although there is a pathway for the Director to relieve an operator of monitoring responsibilities sooner than 50 years, the presumption is that the operator will monitor for *at least* 50 years. EPA has suggested that liability transfer schemes may create "stringency issues" where state law authorizes the permitting agency to release a former permittee from liability for earlier UIC violations.[28] Although the carve-outs provided in H.B. 458 ('25) at § 6(C) may prevent some liabilities from transferring to the state, we encourage OCD to examine whether the liability scheme in New Mexico is truly as stringent as the federal scheme.

Second, the draft rules as drafted do not require that the plume have stabilized—only that the geologic sequestration project no longer pose an endangerment to USDWs. Following Wyoming's lead, OCD should amend these provisions to require verification of plume stabilization during post-injection site care. Importantly, Wyoming defines "plume stabilization" as occurring "when the carbon dioxide stream that has been injected subsurface essentially no longer expands vertically or horizontally and poses no threat to underground sources of drinking water, human health, safety, or the environment, as demonstrated by a minimum of three (3) consecutive years of monitoring data."[29]

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[28] *See* U.S. E.P.A., *EPA Response to Public Comments on the Louisiana Department of Natural Resources' Class VI Primacy Application,* (2023) at 17, accessible at https://www.regulations.gov/document/EPA-HQ-OW-2023-0073-0754.

[29] Wyo. Admin. Code 020.0011.24 § 2(hh-ii).

Reserve3(B)N.(6): (Crosswalk Line 711): This provision specifies that an operator's site closure report must be retained at a "location designated by the Director for 10 years." As discussed supra at Crosswalk Lines 683-684, we believe this period of document retention should be at least 50 years.

Reserve3(B)O.(2): (Crosswalk Line 721): This provision requires that the owner or operator conduct outreach to communities located within the Area of Review during the development of the emergency and remedial response plan, identifying the chain of command for notifying the public in event of emergency, developing protocols for notifying the public about emergencies, and taking into account local language needs. The provision further specifies that the plan must describe how the owner or operator will provide training for local emergency responders, and how community outreach will be maintained throughout the life of the project. In addition to the requirements included, we propose that the owner or operator be required to work directly with—rather than just fund—local emergency responders, to ensure they're adequately prepared for the risks attendant to these projects. We generally support this provision.

RESERVE 4

Reserve 4 B. NMAC – Unitization of Sequestration Facilities: The legislature considered and rejected this scheme in H.B. 457 ('25), and the agency lacks authority to carry this out.

Reserve 4 C. NMAC – Effects of a Unitization Order: The legislature considered and rejected this scheme in H.B. 457 ('25), and the agency lacks authority to carry this out.

Reserve 4 D. NMAC – Ownership of Injected Carbon Dioxide: The legislature considered and rejected this scheme in H.B. 457 ('25), and the agency lacks authority to carry this out.

Reserve 4 E.(2) NMAC – Effects of Certificates: The draft rule provides that OCD may levy regulatory and application fees, and that those fees will be set in rule. First, the agency doesn't appear to have authority to levy regulatory or application fees, unfortunately, but second, it's unclear why the fees would be identified but not established in this rulemaking.

In conclusion, Conservation Groups appreciate this opportunity to comment on the draft Class VI Primacy rules, and encourage OCD to address the feedback provided above.

Sincerely,

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Exhibit 2

Confronting the Myth of Carbon-Free Fossil Fuels

Why Carbon Capture Is Not a Climate Solution

The world is confronting a climate emergency. Avoiding climate catastrophe requires immediate and dramatic reductions in greenhouse gas (GHG) emissions that are possible only with a significant investment of public resources in proven mitigation measures, beginning with eliminating fossil fuel use and halting deforestation. Carbon capture and storage (CCS) and carbon capture, utilization, and storage (CCUS) will not address these core drivers of the climate crisis or meaningfully reduce GHG emissions, and should not distract from real climate solutions.

CCS and CCUS technologies are not only *unnecessary* for the rapid transformation required to keep warming under 1.5°C, they *delay* that transformation, providing the fossil fuel industry with a license to continue polluting. This brief argues that carbon capture technologies:

- Do not remove carbon from the atmosphere, and in fact worsen the climate crisis when used to boost oil production.
- Have not been proven feasible or economic at scale and can only contain a fraction of source emissions.
- Prolong dependence on fossil fuels and delay their replacement with renewable alternatives.
- Create environmental, health, and safety risks for communities saddled with CCS infrastructure, such as pipelines and underground storage.

CCS Isn't Carbon Negative, or Even Carbon Neutral

CCS and CCUS refer to processes that collect or "capture" carbon dioxide generated by high-emitting activities — such as coal- and gas-fired power production or plastics manufacturing — and then transport those captured emissions to sites where they are either used for industrial processes or stored underground.[1]

CCS does not *remove* carbon from the atmosphere, although it is often erroneously conflated with "CO_2 removal" or "negative emission" technology. At best, CCS prevents some emissions caused by the combustion of carbon-based fuels from reaching the atmosphere — provided that the captured gases are not later released.

In practice, however, CCS masks the harmful carbon emissions from the underlying source, enabling that source to continue operating rather than being replaced altogether, while creating additional risks, impacts, and costs associated with the CCS infrastructure itself. Moreover, the injection of captured carbon into oil wells to enhance oil recovery — the most pervasive use of CCS today — exacerbates global warming by boosting oil production and prolonging the fossil fuel era.[2]

Large-Scale CCS is Neither Viable Nor Necessary

The unproven scalability of CCS technologies and their prohibitive costs mean they cannot play any significant role in the rapid reduction of global emissions necessary to limit warming to 1.5°C. Despite the existence of the technology for decades and billions of dollars in government subsidies to date, deployment of CCS at scale still faces insurmountable challenges of feasibility, effectiveness, and expense.

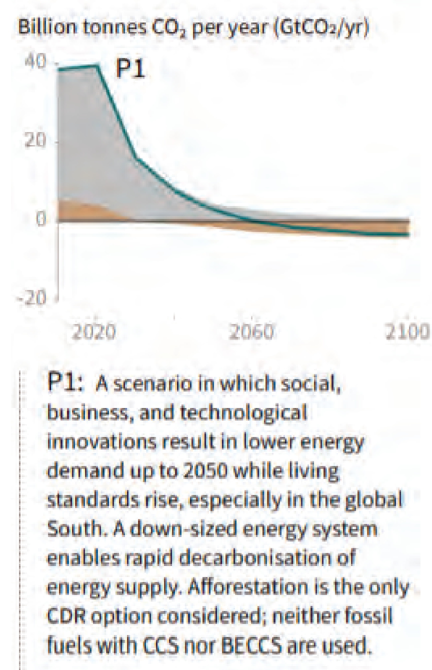
Existing CCS facilities capture less than 1 percent of global carbon emissions. The 28 CCS facilities currently operating globally have a capacity to capture only 0.1 percent of fossil fuel emissions, or 37 megatons of CO_2 annually. Of that capacity, just 19 percent, or 7 megatons, is being captured for actual geological sequestration.[3] The vast majority, as discussed ahead, is being used to produce more oil.

CCS pilot projects have repeatedly overpromised and underdelivered. The Petra Nova carbon capture facility installed at a coal-fired power station near Houston, Texas, in 2017 illustrates the failure of CCS to deliver meaningful emissions reductions and the folly of deploying CCS in service of fossil fuel extraction and use.

During its operation, the CCS system only captured 7 percent of the power plant's total CO_2 emissions, well below the company's promises to reduce CO_2 emissions by 90 percent.[4] The captured carbon from Petra Nova had been used for enhanced oil recovery, but the 2020 collapse in oil price and demand rendered this uneconomic. The CCS operation and the gas plant used to power it have been shut down indefinitely, leaving the coal-fired plant as emissions-intensive as ever.[5]

The surest approach to avoiding climate catastrophe does not involve CCS. According to the Intergovernmental Panel on Climate Change (IPCC), the emissions reduction pathway with the best chance of keeping warming at or below 1.5°C makes *limited to no* use of engineered carbon capture technologies. This pathway involves a rapid phaseout of fossil fuels along with limited carbon removal by *natural sources* such as reforestation

FIGURE 1
IPCC 1.5°C Pathway 1



Graphic Source: IPCC

and enhanced soil carbon uptake.[6] The IPCC points to "uncertainty in the future deployment of CCS,"[7] and cautions against reliance on the technology, given "concerns about storage safety and cost"[8] and the "non-negligible risk of carbon dioxide leakage from geological storage and the carbon dioxide transport infrastructure."[9]

In January 2021, the 1,500 member-organizations of Climate Action Network (CAN) International adopted a shared position statement that the largest network of climate organizations worldwide "does not consider currently envisioned CCS applications as proven sustainable climate solutions." The organizations warned that CCS "risks distracting from the need to take concerted action across multiple sectors in the near-term to dramatically reduce emissions." Accordingly, CAN urged that "[a]ll government subsidies, loans, grants, tax credit, incentives, and financial support for fossil fuels and technologies that use or otherwise support the continued use of fossil fuels, including CCS, should be phased out as soon as possible."[10]

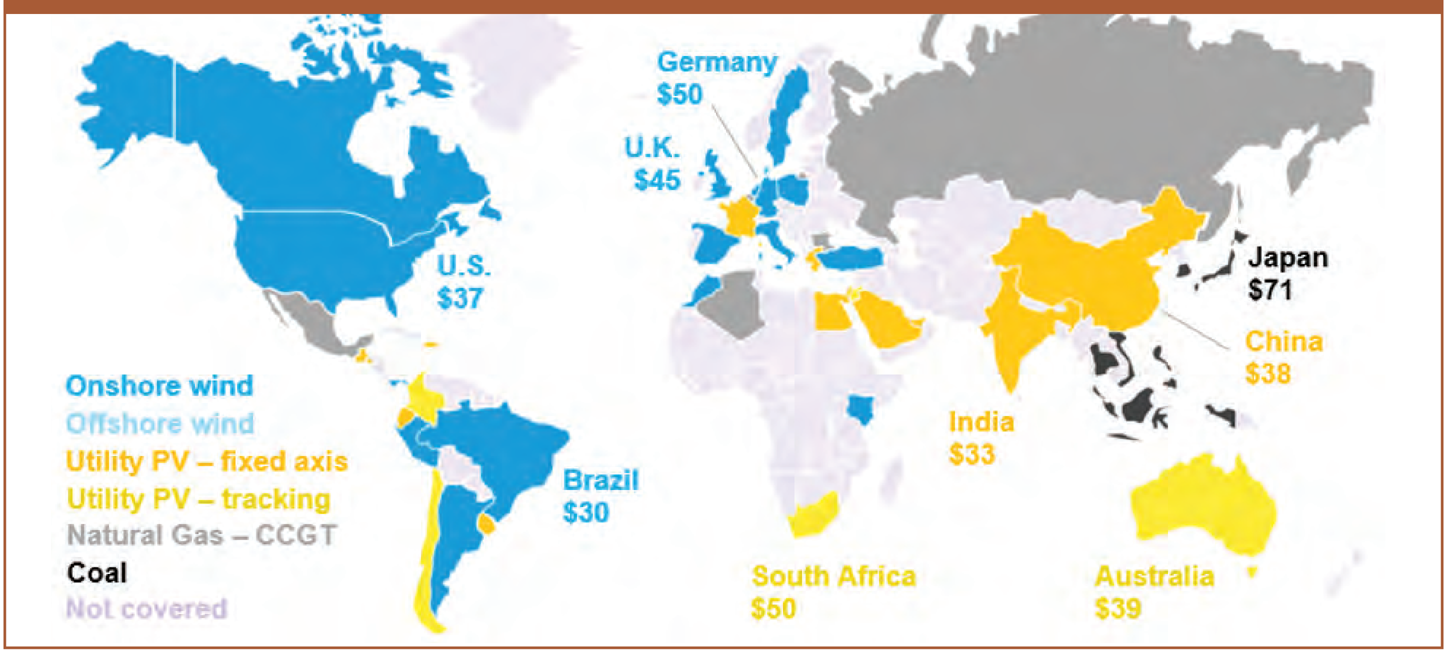
A 1.5°C pathway is possible without CCS. By transitioning the transportation, industry, and building sectors to 100 percent clean, renewable energy through rapid electrification and phase out of fossil fuels, and enhancing natural carbon sequestration through improved land management and restoration, it is possible to keep warming at or below 1.5° C *without* CCS.[11]

Clean energy is also cheaper energy. Plummeting renewable energy costs are rapidly making electrification with clean sources like solar and wind less expensive than producing power with fossil fuels.[12] A 2020 analysis by Bloomberg New Energy Finance found that solar and wind are already the cheapest energy sources for two-thirds of the world's population. Rapidly declining costs make renewable energy cheaper than continuing to operate existing coal and gas facilities in many places.[13]

Similarly, plummeting costs are quickly making battery storage a cheaper option for ensuring grid reliability than new gas peaker plants.[14] The US Energy Information Administration (EIA) projects that renewables will account for 71 percent of new US electricity generating capacity in 2021.[15]

The failure to account for the energy transition's market and technological disruptions to coal- and gas-fired power plants means not only that they are outcompeted

FIGURE 2
Cheapest Source of New Bulk Electricity Generation by Country



Source: *BloombergNEF.* Note: Levelized cost of energy (LCOE) calculations exclude subsides or tax credits. Graph shows benchmark LCOE for each country in US dollars per megawatt-hour. CCGT: Combined-cycle gas turbine.

Photo by Fabrice Duprez via Pixabay

by alternatives and systematically overvalued,[16] but also that "the overwhelming majority of these conventional facilities will become financially unviable and their assets stranded over the next decade or so."[17] Tacking CCS onto these soon-to-be stranded power plants is as economically ill-founded as it is environmentally unsound.

From a purely economic perspective, CCS does not make sense. Economists and energy analysts note that CCS projects are "prohibitively expensive compared to other GHG emissions mitigation options, such as renewable energy and energy storage technologies."[18] Adding CCS onto a fossil-fueled power plant inevitably makes operating the underlying source more expensive. As the authors of the energy transition study summarized above observed, "Coal and gas power plants with integrated carbon capture and storage (CCS) are doubly mispriced (overvalued)."[19] With coal- and gas-fired power stations already becoming more costly than renewable alternatives, adding CCS simply makes them even less economic and even less necessary.

A recent assessment of the economic viability of using CCS with gas-fired power plants demonstrates this reality, noting that mature carbon capture technologies are poorly suited to gas and pose an even larger energy penalty for fossil gas than for coal.[20] For a new-build gas-fired plant, CCS could more than double the construction costs and increase the cost of energy produced (known as levelized cost of energy) by up to 61 percent.[21]

As a result, CCS is not economic for gas-fired power plants even when it takes full advantage of existing federal subsidies, as discussed below, and when the captured carbon is used to produce more oil.[22] The authors of the study proposed a solution of injecting even more federal funding into CCS.

The simpler, surer, and cheaper solution is to end this and similar subsidies for the fossil fuel economy and invest the savings in accelerating the transition to clean energy.

Even for the Hard-to-Decarbonize Industrial Sector, CCS Is Not the Answer

The industrial sector accounted for 27 percent of US GHG emissions in 2019.[23] As the rationale for wide CCS deployment in the energy sector rapidly fades, CCS proponents are increasingly arguing that CCS will be needed to reduce emissions in heavy-emitting industries like steel, cement, petrochemicals, and aluminum. While the challenges to decarbonizing these industries are real, the potential for CCS to contribute to major emission reductions is routinely and often dramatically overstated. All too frequently, the advocacy for industrial CCS overlooks or downplays considerations like cost, alternatives to fossil fuel inputs, and the risks posed by transporting and storing captured carbon underground.

Applying CCS to high-emitting industrial activities, like petrochemical, steel, or cement manufacturing, is not economical. GHG emissions from these industries come from a diverse array of sources, including electricity consumption, on-site fossil fuel combustion, and process emissions, which make installing and operating CCS even more complex and generally more costly than it is in the power sector.

A recent analysis co-authored by a Chevron researcher highlights how these costs and complexities weaken the case for significant CCS deployment in the industrial sector. Beginning with a candidate pool of more than 1,500 US industrial facilities identified by the Environmental Protection Agency, the researchers immediately eliminated nearly 700 facilities, accounting for roughly half of all US industrial emissions, because the industries involved — including oil, gas, and coal production — "are not suitable for carbon capture retrofit."[24] By contrast, a transition away from fossil fuels would dramatically curtail such emissions.

From the remaining 656 facilities, the researchers identified only 123 facilities, less than 10 percent of the 1,500 facilities in the initial pool, that could capture carbon economically, even with full use of available federal subsidies and enhanced oil recovery.[25] And among that handful of facilities, many major sources of GHG emissions could not be captured.

For example, the petroleum refining industry is the largest source of industrial emissions other than fossil fuel production itself, yet less than 19 percent of refinery emissions were amenable to carbon capture. For metals processing, including steel, only a quarter of process emissions were amenable to CCS.[26] In total, the researchers identified only 68.5 metric tons of CO_2 per year from industrial process emissions that could be economically captured,[27] representing just 8 percent of all industrial emissions in the US.

Even this figure significantly overstates the potential of CCS in the industrial sector because the analysis excluded the indirect energy inputs that account for the largest single component of industrial sector emissions.[28] The authors did so on the grounds that the energy provided comes from the electrical grid, meaning associated emissions can be reduced more directly through other means, such as renewable energy.

Renewable sources for electricity and heat can dramatically reduce industrial emissions. Most industrial sector emissions are created by burning fossil fuels to produce the electricity and heat that power

FIGURE 3

Breakdown of the Number of Facilities and Their Emissions by Industrial Sector, Type of Emissions, and CO_2 Capture Potential

	refining[a]	chemicals	bioethanol	metals	minerals	pulp & paper	total
All Facilities in the Continuous U.S. Non-Suppliers of CO_2							
number of facilities	123	360	174	289	369	214	1529
total emissions [$MtCO_2$-eq/yr]	163	138	60	93	114	38	606
SC[b] [$MtCO_2$-eq/yr]	101	70	19	55	30	28	303
PE[b] [$MtCO_2$-eq/yr]	57	68	41[c]	37	84	10	297[c]
Facilities Considered for Carbon Capture Retrofit							
Number of facilities	97	104	174	118	163	0	656
total emissions [$MtCO_2$-eq/yr]	163	82	60	73	96	0	473
SC[b] [$MtCO_2$-eq/yr]	107	39	19	45	15	0	225
PE[b] [$MtCO_2$-eq/yr]	56	39	39	27	81	0	242
captured emissions [$MtCO_2$/yr]	40	26	37	19	72	0	195
Facilities Qualifying for the 45Q Tax Credit							
number of facilities	75	62	155	37	129	0	458
captured emissions [$MtCO_2$/yr]	39	24	36	17	71	0	188

[a]Refining category includes the emissions from the refining process and the hydrogen production at refineries. [b]SC = emissions from stationary combustion; PE = process emissions. [c]Process emissions from the ethanol industry are not reported by the EPA, the total process emissions reported by the EPA would thus equal to 256 $MtCO_2$/yr. In addition, this number excludes emissions from wastewater treatment and landfills that are not studied for point-source carbon capture in this work. Details are available in the Supporting Information.

Photo by HHakim via iStockphoto

manufacturing processes. Thus, decarbonizing the electricity grid by shifting to renewable sources provides the most direct route to slashing emissions in these industries. For example, the World Economic Forum estimates that 60 percent of carbon emissions from electricity-intensive aluminum production could be eliminated simply by producing that electricity from renewable sources.[29] In March 2021, a report by the International Aluminum Institute agreed that decarbonizing electricity grids provides the surest, most direct, and likely most cost-effective pathway to significant emission reductions in this energy-intensive industry.[30]

As currently equipped, the industrial sector uses fossil fuels not only for electricity, but for the heat that fuels industrial processes. Fossil fuel combustion for that heat accounts for about 58 percent of US industrial emissions and about 10 percent of overall global GHG emissions.[31] Electricity from clean power sources like solar and wind has the potential to provide low-carbon heat to many industrial systems.[32]

Concentrated solar thermal systems, for example, use solar energy for generating heat. One company has demonstrated this system works for reaching temperatures of more than 1,000°C.[33] From the heat used in kilns during the process of making cement,[34] to the high energy demand from electricity that goes into producing aluminum,[35] clean sources of electricity could displace fossil fuels consumed in a growing array of industrial processes, dramatically curtailing the largest single source of industrial GHG emissions and, with it, the purported benefits of CCS deployment in those industries.

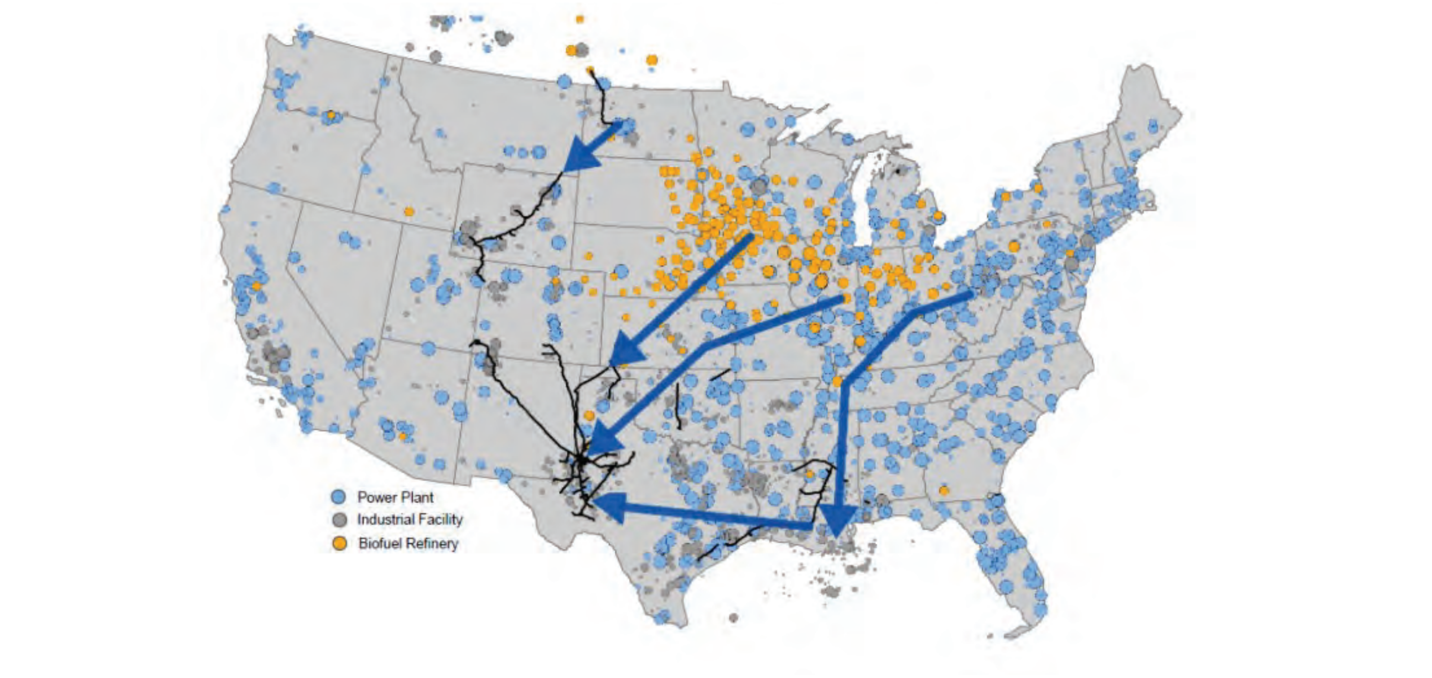
CCS obscures the role of reduction, reuse, and recycling in lowering industrial emissions. Proponents of industrial CCS routinely ignore that one of the most effective ways to reduce industrial emissions from high-emitting sectors like steel, aluminum, and plastics is to reuse existing materials, increase recycling rates, and produce less of the virgin material that is the major driver of emissions. This contrast is particularly notable in the case of plastics and petrochemicals, where the fracking boom of the last decade has driven a massive buildout of new plastics infrastructure even as communities around the world recognize that we need to reduce, not increase, our production and use of disposable plastics.

Even for aluminum, which is already heavily recycled, increasing the recycling of scrap metal could avoid 200 million tons of GHG emissions per year.[36] Replacing virgin steel with increased use of scrap metal or direct reduced iron also has high potential to reduce emissions from steel production — potential that should be tapped, given that CCS technology for steel remains immature and economically unproven, according to industry analysis.[37]

Applying CCS to industrial sources requires massive infrastructure buildout. Even assuming carbon can be captured effectively and economically from an industrial process, that does not assure it can be safely sequestered. The geographic distribution of CO_2 storage sites is a limiting factor for CCS deployment in industry.[38] The overwhelming majority of industrial facilities including those in high-emitting industries like cement, steel, and aluminum, were sited to ensure access to critical

FIGURE 4

Map of CO_2-Emitting Facilities Compared to Viable Geological Storage Sites



Elizabeth Abramson, Regional Carbon Capture and Transport Opportunities for Storage in Louisiana. Presentation to "Developing CCUS Projects in Louisiana and the Gulf Coast" (USDOE/USEA/GCCSI) November 17, 2020. *https://www.globalccsinstitute.com/wp-content/uploads/2020/11/PPT-LA_Day-1-and-Day-2.pdf* at slide 42.

resources like steam, electricity, water, and end markets, not carbon storage.

Accordingly, only a small fraction of existing or proposed facilities in these sectors are located in areas suitable for CO_2 storage. Storing carbon captured from such facilities would demand a vast network of new pipelines, some running hundreds of miles, and carrying hazardous CO_2 through populated areas.

Transporting carbon to storage sites and injecting it underground involves further risks and costs. As discussed more fully below, this reality means that the growing risks of carbon capture will be borne disproportionately by the few communities already living near concentrations of both heavy industry and potential storage or injection sites.

CCS Perpetuates Fossil Fuel Systems and Impacts

By design, CCS enables an underlying emissions-generating activity to continue — by capturing some of the CO_2 it would otherwise emit. The promise of CCS is being used to rationalize — and subsidize — continued investment in fossil fuel infrastructure that would lock in emissions of CO_2 and other pollutants for decades to come.

Even in its idealized form, CCS only prevents a fraction of emissions from the underlying source. At every stage of their lifecycle, including extraction, refining, transport, use, and disposal, fossil fuels release a wide array of pollutants, many of which pose known or suspected hazards to humans and the environment. For example, a study released in February 2021 by Harvard University and University College London researchers found that fine particulate matter (PM2.5) from burning fossil fuels is responsible for millions of deaths worldwide. In 2018, approximately one in five deaths overall, or 8.7 million premature deaths, were linked to PM2.5 pollution from fossil fuels.[39]

CCS does nothing to address these hazards.[40] Indeed, by requiring greater use of fossil fuels to power the CCS process itself, CCS may actually exacerbate them. In the energy sector, there is compelling evidence that the negative climate, environmental, and health impacts of adding carbon capture to fossil fuels are substantially greater than simply replacing fossil fuels altogether with clean alternatives.[41] As discussed more fully above, the deployment of industrial CCS raises similar concerns.

Using captured carbon to produce still more fossil fuels accelerates the climate crisis. At present, carbon capture is not economically viable without enhanced oil recovery or the production of combustible fuels, making the technology inseparable from the fossil economy. Enhanced oil recovery (EOR) is a technique through which CO_2 — either from natural sources or captured carbon — is injected into underground oil reservoirs to boost oil and gas production from old wells. In essence, CO_2 waste products from a fossil fuel-burning activity are used to generate more fossil fuels, propping up the unsustainable fossil fuel energy system.

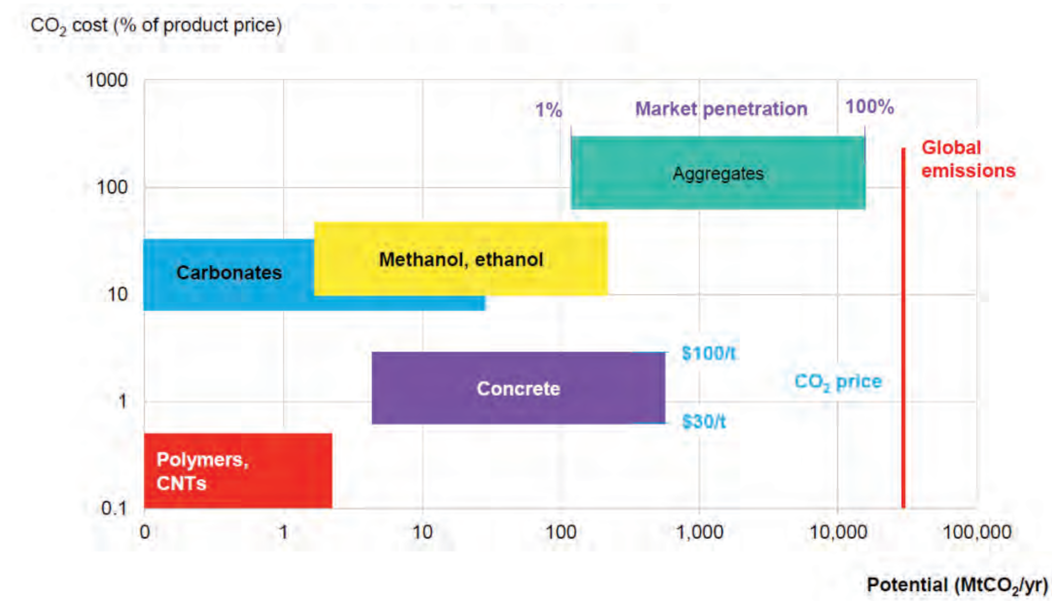
More than 80 percent of all CCS capacity deployed to date has been used for EOR.[42] And the majority of CCS projects in active development also incorporate EOR. The US Department of Energy estimates this could result in up to 48 billion additional barrels of oil used in the US alone by 2030.[43] This is disastrous from a climate mitigation perspective, since it will result in more oil extracted and more carbon emissions from the oil burned. The emissions impact from burning oil produced with CO_2 + EOR is currently excluded from lifecycle analyses touting the technology.[44] While the resulting CO_2 emissions may be invisible to carbon accountants, their presence in the atmosphere and their impact on the climate remains real and significant.

Proponents of CCUS argue that "[t]he most efficient strategy to reduce the concentration of CO_2 in the atmosphere is to convert it to useful chemicals and fuels."[45] But such proposals confront a fundamental challenge: global emissions of CO_2 are orders of magnitude greater than global demand for CO_2 in products. In 2018, the world emitted more than 37 billion tons of CO_2 and other GHGs from fossil fuel combustion for energy and industry.[46] By contrast, it used just 230 million tons of CO_2 for commercial purposes — equal to just 0.5 percent of total annual emissions. Two uses alone — EOR and fertilizer production — account for more than 85 percent of all CO_2 consumed globally.[47] All other commercial and industrial uses combined account for just 20 million tons of CO_2 each year, a mere drop in the bucket.

The touted uses of CO_2 are also unviable. Using captured carbon to produce combustible fuels, including via EOR, defeats any climate mitigation purpose, as the fuels release the carbon back into the atmosphere. Transforming CO_2 into chemicals requires massive

FIGURE 5

CO_2 Utilization Markets and Sensitivity to CO_2 Prices



BNEF Executive Factbook 2021 at 56: https://assets.bbhub.io/professional/sites/24/BNEF-2021-Executive-Factbook.pdf amounts of energy, which is why only a handful of commercialized chemicals use CO_2 in significant quantities.[48] Technologies for embedding captured carbon in plastics, for example, are currently confined to laboratory environments, and neither technologically nor economically proven at scale.[49] Just as importantly, using captured carbon to increase production of plastics — which are themselves made from fossil fuels — would compound the plastics crisis while doing little to address the climate crisis.[50] Proposals to store captured carbon in concrete are no more promising. Storing 1 pound of CO_2 requires 100 times its weight in concrete when embedded in cement mix and over 1,000 times its weight when embedded in standard concrete blocks.[51] Embedding coal combustion wastes or industrial slag in concrete does not eliminate smokestack emissions and increases risks of toxic leaching from the treated materials.[52] Just as using captured carbon to produce more oil increases emissions, embedding industrial wastes into new products does nothing to curb emissions from the activity that generated the waste.

CCS subsidies end up in oil industry pockets. The tax credit for CCS projects (under Section 45Q of the US Internal Revenue Code, which Congress extended in December 2020) is the main federal policy support for CCS. Its biggest beneficiaries are oil companies that claim the credit for injecting carbon into underground oil deposits to produce more oil, through EOR.[53] The tax credit thus functions as a fossil fuel subsidy.[54]

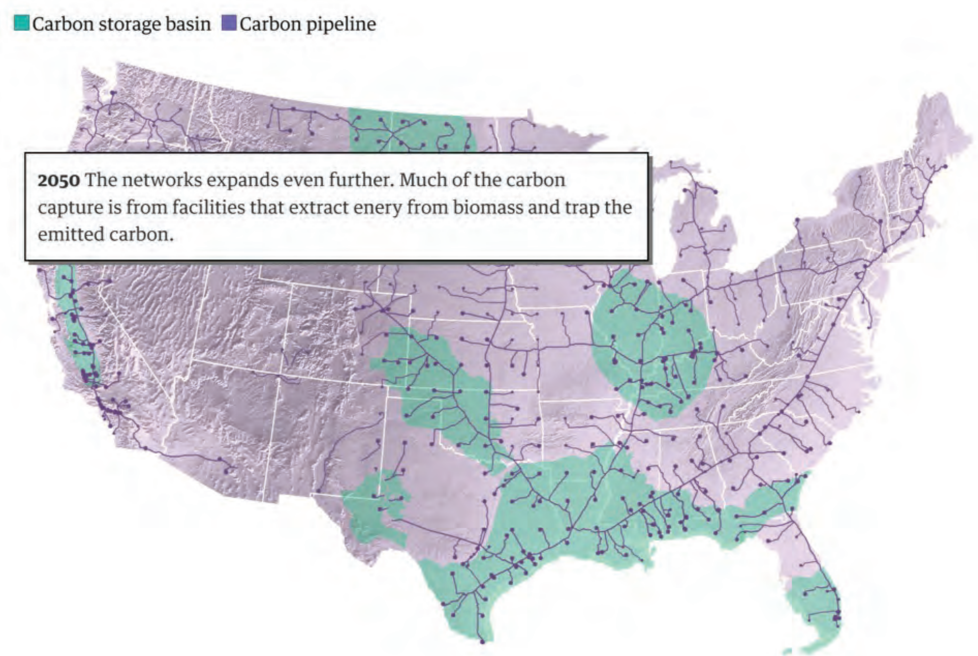
Moreover, the lack of adequate monitoring of CCS activities means claimed credits may be based on little more than hot air, not on stored carbon.[55] For example, an investigation by the US Treasury's Inspector General for Tax Administration found that fossil fuel companies improperly claimed nearly $900 million in tax credits under Section 45Q.[56]

The push for carbon capture and storage primarily benefits the fossil fuel industry. The most vocal and active proponents of CCS are oil and gas, petrochemical, and utility companies. They tout the necessity and promise of carbon capture to protect a business model that is contributing to climate catastrophe.[57]

In addition to investing directly in carbon capture ventures, companies in the fossil fuel industry promote

FIGURE 6

Map of Proposed US CO_2 Pipeline Network



Oliver Milman, Alvin Chang & Rashida Kamal, The race to Zero: can America reach net-zero emissions by 2050. The Guardian (March 15, 2021). https://www.theguardian.com/us-news/2021/mar/15/race-to-zero-america-emissions-climate-crisis

CCS advocacy, research, and policy through an array of corporate consortia, industry-government working groups, and funding partnerships with universities. For example, the Global CCS Institute, an international think tank dedicated to accelerating CCS deployment, includes various coal, oil and gas, and energy and utility companies as members, and a handful of national and sub-national governments.[58] Corporate polluters benefit from promoting CCS, while the environmental and community impacts of scaling up the CCS industry are too often ignored.

CCS Poses a Growing and Poorly Understood Threat to Communities & the Environment

Scaling up the technology and infrastructure required to capture, compress, transport, and store CO_2 entails significant risks.[59] Whether paired with fossil fuel power plants or industrial manufacturing, CCS technology demands massive infrastructure buildout. In terms of scale, it is estimated the CCS industry and associated infrastructure would need to be two to four times larger by 2050 than the current global oil industry.[60] As the IPCC has noted, extensive deployment of CCS "will require a large network of pipelines."[61] To date, the heavy environmental footprint and safety and health hazards[62] associated with CCS infrastructure have been largely overlooked.[63]

The transportation of compressed CO_2 raises a host of health and safety concerns. Especially when moved over long distances and/or through heavily populated areas, piping CO_2 poses risks similar to those associated with fossil fuel pipelines, from land disturbance and water contamination to the danger of explosions and other accidents. These risks are rarely disclosed or discussed in public discussion of CCS.

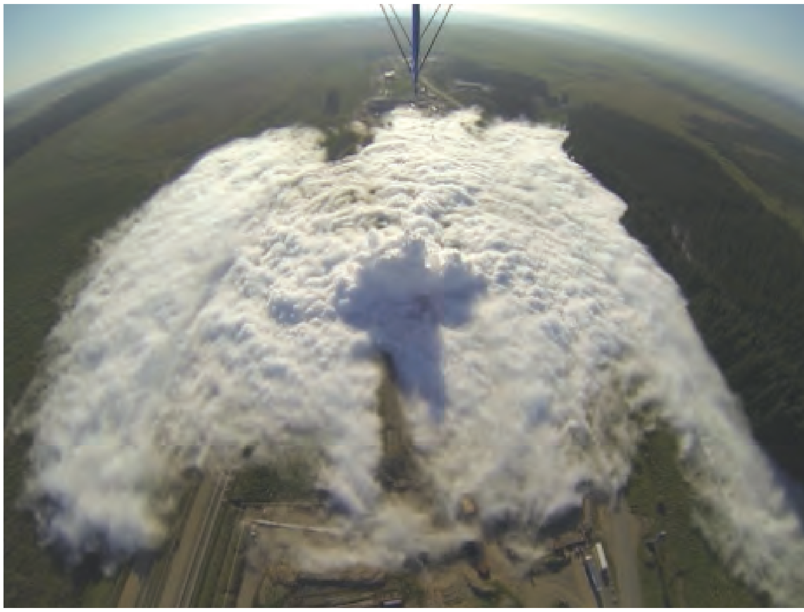
Effective transport through pipelines requires that CO_2 be shipped at very high pressure and extremely low temperatures, demanding pipelines capable of withstanding those conditions. The presence of moisture or contaminants can make this condensed CO_2 corrosive to the steel in those pipelines, increasing the risk of leaks, ruptures, and potentially catastrophic running fractures.

Because of the intense pressures involved, explosive decompression of a CO_2 pipeline releases more gas, more quickly, than an equivalent explosion in a gas pipeline.[64] Video recordings of pipeline failure tests under controlled conditions demonstrate that even a modest rupture can spread freezing CO_2 over a wide area within seconds.[65] The emergence of a running pipeline rupture could extend impacts the entire length of a pipeline segment.[66]

As a paper published by the Institution of Chemical Engineers Symposium cautions: "The combination of the massive amount of CO_2 released in a relatively short period of time, the resulting dense cloud followed by solid discharge and its slow sublimation will pose a major challenge to safety practitioners when dealing with the hazards associated with the failure of pressurized CO_2 pipelines."[67]

The IPCC recognizes that "carbon dioxide leaking from a pipeline forms a potential physiological hazard for humans and animals."[68] These risks take several forms.

The explosive rupture of a pipeline and its associated shockwave pose immediate physical risks to nearby people and property. In areas closest to the pipeline, a release of CO_2 can quickly drop temperatures to minus 60°C, coating the surrounding area with super-cold dry ice.[69] At high concentrations, CO_2 is a toxic gas and an



CO_2 cloud from a rupture test performed at DNV GL Spadeadam, Photo: DNV GL

Photo Credit: Mississippi Emergency Management Agency

asphyxiant capable of causing "rapid 'circulatory insufficiency', coma and death."[70] And potential contaminants in CO_2 streams, such as hydrogen sulfide (H_2S) can dramatically compound these risks.[71]

Accidents are inevitable as CO_2 pipelines are increasingly built in populated areas. In February 2020, a 24-inch high-pressure pipeline containing carbon dioxide and sulfur dioxide ruptured in Yazoo County, Mississippi. According to the Mississippi Emergency Management Agency, more than 300 residents were evacuated and[46] dozens were hospitalized.[72] The pipeline owner, Denbury Enterprises, operates hundreds of miles of CO_2 pipelines in the Gulf Coast and Rocky Mountain regions. At least two Denbury pipelines run through the heavily polluted petrochemical corridor known as Cancer Alley,[73] predominately populated by communities of color.

These safety hazards and environmental risks fall disproportionately on marginalized communities. Fossil fuel and petrochemical infrastructure, and the threats to health and public safety that infrastructure creates, already overburden Black, Brown, and Indigenous communities. The deployment of CCS threatens to significantly increase these risks, particularly in the regions being most heavily targeted for new CCS buildouts.

Both the Gulf Coast of Texas and Cancer Alley in southern Louisiana have been widely touted as potential epicenters for industrial CCS development due to existing concentrations of oil, gas, and petrochemical infrastructure, along with oil fields and salt domes that are the most viable injection and storage sites.[74] CCS proposals in other regions also focus on areas where energy and industrial infrastructure are concentrated, which are typically in or adjacent to poor neighborhoods and communities of color. The expansion of CCS would add a significant new source of pollution and safety risks in Black, Brown, and Indigenous communities already suffering the disproportionate and deadly impacts of environmental racism.

Conclusion

CCS and CCUS are not only unnecessary, ineffective, uneconomic, and unsafe; the technologies are also exceptionally risky, prop up the fossil fuel industry and carbon-intensive industrial activities, and distract from the urgent task of transitioning away from fossil fuels at a time when the US and the world must dramatically accelerate that transition. These technologies, and the dangerous myth they perpetuate of climate-safe fossil fuels, have no place in US climate policies and financing. Such policies should focus instead on phasing out fossil fuels and implementing proven climate mitigation strategies on an urgent, comprehensive basis, reflecting their fundamental importance for this and all future generations.

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Confronting the Myth of Carbon-Free Fossil Fuels: Why Carbon Capture Is Not a Climate Solution was prepared by Dana Drugmand and Carroll Muffett of the Center for International Environmental Law (CIEL), with editorial assistance from Nikki Reisch, Steven Feit, and Cate Bonacini.

WildEarth Guardians

Exhibit 3

CENTER for BIOLOGICAL DIVERSITY Because life is good.

September 26, 2025

Benjamin Bajema, Policy Director
New Mexico Energy, Minerals and Natural Resources Dept.
1220 South St. Francis Drive
Santa Fe, NM 87505

Submitted via email
benjamin.bajema@emnrd.nm.gov

Re: Public Comment on New Mexico Class VI Primacy Draft Rules

Dear Mr. Bajema:

The Center for Biological Diversity submits these comments in response to the Oil Conservation Division's (Division) *Notice and Request for Public Comment on the Oil Conservation Division's Draft Rules to EPA for Class VI Primacy*, published August 22, 2025.

As an initial matter, we have grave concerns about the State obtaining primacy over Class VI wells because New Mexico lacks the capacity to properly and safely regulate these wells. Further, the State's goal to use Class VI wells to bolster new carbon capture and sequestration (CCS) projects will perpetuate fossil fuel production in New Mexico. Obtaining primacy over Class VI wells is not a solution to the climate crisis or the pathway to decarbonization in New Mexico.

The science is clear that we must rapidly phase out fossil fuel use and production to avert the worst harms of the climate crisis.[1] After billions of dollars of investment and decades of development, deployment of CCS has proven to be ineffective, uneconomic, and unwise,[2] consistently failing to meet the greenhouse gas (GHG) emission reductions the technology has promised.[3] CCS is a dangerous delay tactic championed by the fossil fuel industry and other polluters to continue business as usual while diverting resources from the vital transition to clean, cheaper renewable energy.[4] Rather than turning away from fossil fuel production and

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[1] *E.g.*, Wolf, Bullard, Buonocore, et al., *Scientists' warning on fossil fuels* (Mar. 2025), https://academic.oup.com/oocc/article/5/1/kgaf011/8099165.

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[3] IEEFA, THE CARBON CAPTURE CRUX: LESSONS LEARNED (Sept. 2022), https://ieefa.org/resources/carbon-capture-crux-lessons-learned.

[4] The IPCC cautions against overreliance on CCS and related technologies, noting that their future deployment is uncertain, they face multiple feasibility constraints, and could have adverse impacts on human rights and ecosystems. The modeled pathways that provide the greatest chance of staying below 1.5ºC (2.7°F) without overshoot (i.e., without experiencing global temperature increases beyond 1.5°C) avoid reliance on CCS and BECCS and instead focus on rapid and dramatic phaseout of fossil fuels. *See*

towards clean energy, the State seeks primacy over Class VI wells as a means to perpetuate fossil fuel production—continuing our legacy as a state that drives the global climate crisis.

Concerns presented by CCS are only exacerbated by the proposals of states such as New Mexico for state-level primacy over Class VI wells. On a general level, primacy threatens to erode critical oversight during the Class VI permitting process and will create a patchwork of regulation among different states, many of which, like New Mexico, do not have the resources to adequately administer Class VI programs. Our concerns with primacy in the Class VI context include:

- **Fast-tracking Permits:** Primacy will enable the fast-tracking of Class VI permits. In EPA's own words to Congress, "[Geologic storage] is a complex process that is highly dependent on site-specific conditions; therefore, *a robust and comprehensive permit application and permit review process is fundamental* to preventing endangerment of [underground sources of drinking water] from these activities."[5] Yet examples from other states demonstrate that often state review of permits is truncated. For example, North Dakota, the first state to obtain primacy over Class VI wells from EPA, permitted its first Class VI well *less than five months* after receiving the project application.[6] In a virtual stakeholder outreach meeting this past May, New Mexico Oil Conservation Division staff suggested that permit review for Class VI wells under Division oversight would also likely be faster than under the federal EPA. With fewer resources and less experience than the EPA—in addition to a long history of cooperation with New Mexico industry—it is unlikely that the Division will provide as robust a review of forthcoming Class VI permit applications as EPA has historically done. State Class VI primacy vests regulatory authority over industry with the state agency that is most incentivized to create a lax regulatory environment for that same industry in an effort to attract and retain its purported investments.
- **Demonstrated Lack of Capacity:** The Division has already demonstrated an inability to adequately administer primacy over Class II wells. In the Ground Water Protection Council's 2020 Peer Review of New Mexico's Class II UIC Program, the Council reported that staffing shortages between forty and sixty percent "have placed the OCD in a near crisis situation from a programmatic standpoint….[with] insufficient staff available to manage critical aspects of a Class II UIC program."[7] The Council concluded that "[w]ithout significant staffing increases…and enactment of staff retention efforts for both field and office positions, the State of New Mexico is likely to face an increasing threat of harm to USDWs and an elevated risk to public

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CIEL, UNMASKING CLEAR WARNINGS ON OVERSHOOT, TECHNO-FIXES, AND THE URGENCY OF CLIMATE JUSTICE, https://www.ciel.org/wp-content/uploads/2022/04/IPCC-Unsummarized_Unmasking-Clear-Warnings-on-Overshoot-Techno-fixes-and-the-Urgency-of-Climate-Justice.pdf.

[5] EPA, "Report to Congress Regarding Recommendations to Improve Class VI Permitting Procedures for Commercial and Research Carbon Sequestration Projects," 19 (Oct. 28, 2022).

[6] Ethanol Producer Mag., "Red Trail Energy begins carbon capture and storage" (July 18, 2022), https://ethanolproducer.com/articles/19447/red-trail-energy-begins-carbon-capture-and-storage/; *see also* North Dakota: Class VI wells, Order 31453, https://www.dmr.nd.gov/oilgas/or31453.pdf.

[7] Ground Water Prot. Council, "State of New Mexico Class II UIC Program Peer Review" (Jan. 8, 2020), https://www.gwpc.org/wp-content/uploads/2019/09/New_Mexico_Peer_Review_1_8_2020.pdf.

health and safety."[8] These concerns are reflected in the Division's enforcement efforts today, as it continues to cite a lack of capacity in its struggle to enforce other programs it administers and there is no reason to believe that OCD will be better resourced to manage administration of Class VI wells. Taking on primary enforcement authority for Class VI wells will only increase threats to the health and safety of New Mexicans and their environment.

It is vital that, if New Mexico is to pursue primacy, the State's Class VI regulatory framework is robust enough to protect New Mexicans from potential environmental, health, and financial impacts to the maximum extent practicable. Below, we include some of our broad concerns with the rule as currently drafted. An appendix is also attached with detailed comments and recommendations for the draft rule (see Appendix 1).

- **Notice and Public Participation:** OCD must prioritize transparency and public participation in all Class VI permitting and procedures, and the public must be able to object based on concerns for public health, safety, and the environment. Currently, the draft rule only nods to community outreach as a component of permitting but does not prescribe specific procedures for outreach or articulate enforcement consequences when outreach does not happen.[9] Meaningful community outreach, clearly defined by the rule, must be a prerequisite to permitting any project and the public should have access to important records without being required to submit an Inspection of Public Records Act (IPRA) request. Requirements for notice and hearing must be strong enough to ensure all potentially affected community members are aware of projects and are afforded an opportunity to participate in the decision-making process. Local tribal, county, and municipal governments should be consulted concerning projects that would be sited within their jurisdictional boundaries.
- **Permitting:** The proposed rule does not include consideration of public health, safety, and the environment in the permitting process, and instead only proposes protections for Underground Sources of Drinking Water (USDWs). This is a critical flaw. The Division must undertake robust review of each permit application to identify risks to public health, safety, and the environment, and must deny any project that cannot reduce such risks to negligible levels. Project risk analysis should weigh the project's cumulative impacts—there is currently no such requirement—and impacts to frontline communities. During stakeholder meetings, the Division stated a commitment to environmental justice and transparency, but this is not reflected in the draft rule. Further, tonnage fees should be established by this rulemaking and must be sufficient to support the State's ongoing responsibilities for site monitoring and care post-closure, responsibilities extending in perpetuity. Cleanup costs must not be passed onto the public as they often have been with oil and gas well abandonment.
- **Enforcement, Monitoring, and Reporting:** Strong monitoring and enforcement language must lay the groundwork for regulatory accountability and transparency to

[8] *Id.*

[9] *E.g.*, Reserve3.B(C)(1)(u), The owner or operator shall submit "[a] summary of community outreach activities conducted with communities located within the AoR prior to submittal of the permit application."

preempt the enforcement shortcomings that plague other programs overseen by the Division. The monitoring and reporting intervals in the rule should be more frequent and should provide the Division with clear, nondiscretionary enforcement pathways for violations, especially violations resulting in risk to public health, safety, or USDWs. Enforcement authority over an operator should expressly continue long past site closure. All enforcement, monitoring, and reporting records, particularly those concerning well plugging and site closure plans, must be maintained indefinitely by the Division to ensure public safety and the ability for the Division to competently execute ongoing site monitoring and care in perpetuity.

- **Financial Assurance:** Unplugged and abandoned oil and gas wells are already set to cost the public billions of dollars despite the financial assurance provisions in place.[10] Class VI wells must not further contribute to the heavy financial burden on public resources. The cost estimates informing financial assurance amounts, including monetary values for endangerment findings, should be reviewed by an independent expert, updated annually, and available to the public for review. The opportunity for Class VI well operators to self-insure their projects must be eliminated. Additionally, it must be mandatory for the Division to reject any financial instrument that is insufficient to meet the obligations it is meant to secure.

Given the many problems associated with state-level primacy in the Class VI context, we urge the Division to dramatically strengthen its Class VI rule to better protect New Mexicans, the environment, and Underground Sources of Drinking Water from the myriad risks associated with this industry.

We thank you for considering these comments.

Sincerely,

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[10] *E.g.*, NM Legis. Fin. Comm., POLICY SPOTLIGHT: ORPHANED WELLS, 15–22 (June 24, 2024), https://www.nmlegis.gov/Entity/LFC/Documents/Program_Evaluation_Reports/LFC%20Policy%20Spotlight%20-%20Orphaned%20Wells%20-%20Final.pdf.

Appendix 1: Class VI Primacy Draft Rule Comments and Recommendations by Line[11]

1. Definitions

Line 73 Reserve1(A)(4)	The rule would provide more protection to USDWs, the public, and the environment if a minimum Area of Review was set, at least ¼ mile from the project as a default, with this radius extending further than ¼ mile as required by calculation of the "zone of endangering influence."
Line 90 Reserve1(A)(21)	"Geologic sequestration means the long-term containment of a gaseous, liquid, or supercritical carbon dioxide stream in subsurface geologic formations…"

[11] Line numbers correspond to those listed in the *Crosswalk for New Mexico UIC Regulations Submitted with Primacy Applications Under Section 1422 of the SDWA*, accessible on the Division's website at the following link: https://www.emnrd.nm.gov/ocd/wp-content/uploads/sites/6/Crosswalk_NM-Class-VI-Primacy_EPA-Submittal_with-NM-Amendments.pdf.

	This definition could be stronger if the word "long-term" was substituted for the word "permanent."
Line 99 Reserve1(A)(30)	It is unclear from the language of the rule how a "major facility" determination will be made by the Director in the Class VI context.
Line 338 Reserve3.A(A)(1)	The definition of "abandoned well" highlights the need to explicitly include provisions addressing the identification and treatment of "inactive," "idle," and/or "temporarily abandoned" Class VI wells in the rule.
Line 354 Reserve3.A(A)(17)	The definition of "plugging" only requires preventing the "flow of water, oil or gas into or out of a formation…"; this definition unnecessarily excludes the need to prevent the flow of other fluids, chemicals, or pollutants.
Line 387 Reserve3.B(B)(9)	The definition of "Post-injection site care" should include public health, safety, and the environment alongside USDWs as entities that post-injection site care should protect. I.e., "…to ensure that USDWs, public health, safety, and the environment are not endangered…"

2. Enforcement

E.g., line 162 Reserve2.B(B)(2)	"For Class I, II, III, and VI wells, if any water quality monitoring of an underground source of drinking water indicates the movement of any contaminant into the underground source of drinking water, except as authorized under part 146, the Director shall prescribe such additional requirements for construction, corrective action, operation, monitoring, or reporting (including closure of the injection well) as are necessary to prevent such movement." The rule should include here, or as a separate provision, a mechanism for the public to participate in this process, such as to identify or report suspected contamination of drinking water or to report other concerns to the Division that may trigger Director review or water quality monitoring of an injection facility.
Line 324 Reserve2.E(C)(2)	"Any schedules of compliance shall require compliance as soon as possible, and in no case later than 3 years after the effective date of the permit." This three-year limit should be reduced with the opportunity of an extension for good cause upon findings by the Director.
Line 570 Reserve3.B(I)(1)	"Except during stimulation, the owner or operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW."

	A mandatory minimum enforcement action should be set for an operator whose injection pressure initiates fractures into the confining zone(s) or causes the movement of injection or formation fluids that endanger a USDW. Public health, safety, and the environment should be protected potentially endangered entities in this language as well. (E.g., "…or cause the movement of injection or formation fluids that endangers public health, safety, the environment, or a USDW."

3. Extension, modification, revocation, and termination of permits

Line 4 Reserve1(C)(1)	The New Mexico rule appears to have removed language from the federal regulations allowing permits to "be modified, revoked and reissued, or terminated either at the request of any interested person..." This language and important avenue for public participation should be reinserted.
Line 64 Reserve1(I)(2)	As written, a permit to construct is valid for two years before automatically terminating, at which point the Director may extend for good cause if the Division "determines that the delay is justified and consistent with the objectives of the Class VI program." The showing necessary, or examples thereof, to support a permit extension should be clarified (e.g., what is weighed to determine a justified delay, what objectives of the Class VI program will be used, etc.) and the public should be provided an opportunity to comment on the decision to extend a permit based upon any interactions with the permittee during the initial two-year period.
Line 226 Reserve2.D(G)	The phrase "When the Director receives any information…" should expressly include information received from the public via an established reporting process. Alternatively, a separate public reporting provision should be added to the rule to address this issue. See the comment concerning line 162, *supra*.
Line 251 Reserve2.D(H)(1)(c)	As currently drafted, the Director *may* terminate a permit based upon, among other causes, a "determination that the permitted activity endangers human health or the environment and can only be regulated to acceptable levels by permit modification or termination." In such instance—when there is no way to regulate an activity to acceptable levels of endangerment to human health or the environment—termination or modification of such permit should be mandatory.
E.g., lines 257, 258, 260	Because "minor modifications" are not subject to public participation provisions, there must be explicit parameters around when modifications are considered minor instead of major. The current list of

Reserve2.D(I)(4), (5) and (7)	minor modifications includes actions that, depending on circumstances, might be better classified as major modifications for which it would be important to have public review. For example: 1) Change of operator, 2) change in quantities or types of fluids injected which are within the capacity of the facility as permitted, 3) changes in plans such as the testing and monitoring plan, post-injection site care or closure plan, and emergency response plan

4. Transitioning from Class II to Class VI

General	The rule would be stronger with additional provisions regulating the transition of Class II wells to Class VI wells. These could include, for example, standards for materials and construction during such a transition and ensuring that all Class II to Class VI transitions include full public notice and participation to the same extent as initial Class VI applications.
Line 166 Reserve 2.B(E)(1)	"Owners or operators that are injecting carbon dioxide for the primary purpose of long-term storage into an oil and gas reservoir must apply for and obtain a Class VI geologic sequestration permit when there is an increased risk to USDWs compared to Class II operations." There is decreased regulation of and less protection from the operations of Class II wells, despite similar concerns for endangerment of USDWs as there are with Class VI wells. As such, an owner or operator should be required to apply for a Class VI permit for any Class II well once there is either 1) an increased risk to USDWs *or* 2) the primary purpose of the well becomes the injection of CO_2 for permanent storage; either change should be sufficient to trigger a Class VI application.
Line 166 Reserve 2.B(E)(1)	This provision would be more protective if it included increased risk to public health, safety, or the environment along with increased risk to USDWs.

5. Permit application

Line 422 Reserve3.B(C)(1)(t)	The list of contacts submitted to the Director should include contact information for representatives of local government (e.g., counties, municipalities), and information for schools, childcare centers, school governing bodies, police, fire departments, emergency service agencies, and first responder agencies responsible for ensuring public safety. Section 1406(b) of Colorado's proposed Class VI rules provides an example of how broad notice provisions might look.

Line 426 Reserve3.B(C)(3)	"Prior to granting approval for the operation of a Class VI well, the Director shall consider the following information:" Information learned during public comment and community input received during the public participation process should be considered by the Director in deciding whether to grant approval for the operation of a Class VI well.
E.g., lines 426, 432 Reserve3.B(C)(3)(f)	This section should require findings by the Director that all operator obligations, including those regarding necessary corrective action, have been fulfilled before the Director approves the operation of a Class VI well.

6. Corrective action

Line 457 Reserve3.B(E)(4)	"Owners or operators of Class VI wells must perform corrective action on all wells in the area of review that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate." This subsection should be amended to not only require corrective action to prevent the movement of fluids into USDWs, but to include any additional corrective action required, if any, to protect public health, safety, and the environment. The rule should outline the minimum requirements for "use of materials compatible with the carbon dioxide stream."
Line 457 Reserve3.B(E)(4)	No permit to operate a Class VI well should be granted before the Director has found that all corrective action required under this section is complete. If additional corrective action is identified as necessary during an Area of Review reevaluation and has not been completed within a period established by the Director following such reevaluation, the operator's permit for the injection well must be suspended until the required corrective action has been completed.

7. Siting

General	There is currently no setback requirement for Class VI injection projects in the draft rule, despite the danger these projects pose to public health and safety. Class VI projects should have a setback requirement precluding them from being constructed in proximity to certain types of surface infrastructure such as residential homes and high occupancy buildings like schools, hospitals, and childcare centers. Section 1411(c) of

	Colorado's proposed Class VI rules provides an example of the form such a setback requirement might take.
General	There are currently no robust considerations of environmental justice or of a project's potential impacts on frontline communities in the draft rule, despite the Division citing this as an important component of its planned rule during early stakeholder meetings. Section 1410 of Colorado's proposed Class VI rules provides procedures for analysis of an injection project's potential effects on disproportionately impacted communities. Considering the commitment to environmental justice and transparency that the Division has articulated, these provisions are worth reviewing to strengthen the community outreach requirement in the draft rule.
General	There are currently no considerations of cumulative impacts of a Class VI injection project in the draft rule. Colorado's proposed Class VI rules provide various procedures to incorporate analysis of an injection project's potential cumulative impacts into siting and permitting decisions; it would be helpful for the Division to review these provisions in order to strengthen New Mexico's rule.

8. Permit conditions

Line 215 Reserve2.D(D)(1)	As written, "the commissioner" shall conduct permit reviews no less frequently than once every five years. It appears this may be meant to read "the Director," in reference to the director of the approved state program. To the extent that the Division will undertake periodic permit reviews, these should be done more frequently (e.g., once every two years or at a frequency properly tailored to the expected timeline of the injection project).
Line 301 Reserve2.E(A)(13)(d)	"The permittee has not received notice *from* the Director of his or her intent to inspect or otherwise review the new injection well within 13 days of the date of the notice in paragraph (m)(1) of this section, in which case prior inspection or review is waived and the permittee may commence injection." The current language allows prior inspection for a new injection well to be waived automatically if the Director does not provide notice to the permittee of the Division's intent to inspect the new well within 13 days of the permittee informing the Division of the well's completion. This period should be lengthened, especially considering the Division's ongoing concerns about capacity limitations.

9. Fees

Reserve4(E)(2), pg. 263 of crosswalk	"The division *may* levy on operators the following fees, which shall be paid to the division and deposited in the oil conservation division systems and hearings fund:" (emphasis added) It is unclear whether the Division has the authority to levy any fee for which it has not received statutory authorization. The fees articulated here would have been authorized by HB 457; however, that bill did not pass the 2025 legislative session. Were the Division to have such authority, any fees applicable to an operator of a Class VI well must be mandatory.
Reserve4(E)(2)(a) and (b), pg. 264 of crosswalk	The current language of the rule states that both the "annual regulatory fee" and the "application fees" will be established by the Division by rule. As noted above, it is unclear whether the Division has the authority to levy these fees, which have not been authorized by statute after HB 457 did not pass during the 2025 legislative session. However, were the Division to have authority to levy these fees, both fees should be established in this rulemaking.
Reserve4(E), pg. 263 of crosswalk	The current rule does not establish a fee per metric ton of CO_2 injected, the proceeds of which are deposited into the geologic carbon dioxide long-term storage stewardship fund. NMSA 1978 § 74-14-5 (2025) mandates this fee be "not less than ten cents ($.10) per metric ton." A tonnage fee should be established by this rulemaking, and it should be far greater than the $.10/ton statutory floor, ideally within the $.32 to $.62 range. For example, see the fee range employed by Illinois. 415 ILCS 5/59.17.

10. Financial assurance

Lines 471, 494 Reserve3.B(F)(1)(a)(v), Reserve3.B(F)(1)(f)(v)	Self-insurance should not be available to satisfy financial assurance requirements.
Line 473 Reserve3.B(F)(1)(a)(vii)	"Any other instrument(s) satisfactory to the Director." There is no reason for additional methods of financial assurance to be available; those listed in the rule—assuming that self-insurance provisions are stricken—are sufficient.
Line 474 Reserve3.B(F)(1)(b)	It is unclear as written how the Director will determine whether the financial assurance is sufficient to cover the project costs outlined in this section. This finding should be based upon the independently reviewed and verified estimate of costs detailed in the comment to

	Line 504, *infra*. Financial assurance should include the full amount of all known costs (e.g., the cost of performing corrective action on wells in the Area of Review as may be required during the life of the project, plugging the injection well(s), post-injection site care and site closure)) and the full amount of all reasonably foreseeable emergency and remedial response costs.
Line 479 Reserve3.B(F)(1)(c)	"The financial responsibility instrument(s) must be sufficient to address endangerment of underground sources of drinking water." This provision must include endangerment to public health, safety, and the environment. These monetary valuations of endangerment should be reviewed by an independent expert.
Line 488 Reserve3.B(F)(1)(e)(3)	"The Director *may* disapprove the use of a financial instrument if he determines that it is not sufficient to meet the requirements of this section." (emphasis added) If a financial assurance instrument is not sufficient to meet the requirements of the section, the Director's disapproval of it must be mandatory.
Lines 481, 491 Reserve3.B(F)(1)(d)(i), Reserve3.B(F)(1)(f)(ii)	These provisions would be stronger if the exact minimum values required (e.g., "minimum rating," "minimum capitalization") were provided by the Division.
Line 495 Reserve3.B(F)(1)(f)(vi)	"An owner or operator who is not able to meet corporate financial test criteria may arrange a corporate guarantee by demonstrating that its corporate parent meets the financial test requirements on its behalf." This option to satisfy financial assurance requirements should be removed.
Line 504 Reserve3.B(F)(3)	The "detailed written estimate, in current dollars, of the cost of performing corrective action on wells in the area of review, plugging the injection well(s), post-injection site care and site closure, and emergency and remedial response" should be reviewed and verified by a third-party expert of the Division's choosing. This estimate should be updated on an annual basis (e.g., Wyo. Ch. 24 § 19(c)) and the estimate methodology should be available to the public for review.

11. Post-closure plan; ongoing site monitoring and care

Line 387 Reserve3.B(B)(9)	The definition of "Post-injection site care" should ensure protection of public health, safety, and the environment alongside USDWs. I.e., "…to ensure that USDWs, public health, safety, and the environment are not endangered…"

Line 502 Reserve3.B(F)(2)(b)(i)	"…if all wells drilled or acquired under that financial assurance have been plugged and abandoned and the location restored and remediated and released pursuant to § 20.6.2.5.M NMAC, § 19.15.25.9 NMAC through § 19.15.25.11 NMAC." This language references the existing rules for plugging and abandoning wells under the Oil and Gas Act. The Division should be sure that the current regulations concerning plugging and abandonment in other programs it oversees sufficiently contemplate the unique nature of fluids and circumstances involved in the Class VI well context and provide all necessary protections.
Line 666 Reserve3.B(M)(2)(j)	"Upon successful completion of well closure, the owner or operator shall comply with § 19.15.25.10 NMAC to properly abandon the well and location." See comment concerning line 502, *supra*.
Lines 682-687 Reserve3.B(N)(2)	Post-injection site care and site closure must include preventing endangerment to public health, safety, and the environment alongside preventing endangerment to USDWs. E.g., "no longer poses a risk of endangerment to the public health, safety, environment, or USDWs."
Line 684 Reserve3.B(N)(2)(b)	"…the Director may approve an amendment to the post-injection site care and site closure plan to reduce the frequency of monitoring or may authorize site closure before the end of the 50-year period or prior to the end of the approved alternative timeframe, where the owner or operator has substantial evidence that the geologic sequestration project no longer poses a risk of endangerment to USDWs." It is not clear what showing an owner or operator must make to satisfy the standard of "substantial evidence that the geologic sequestration project no longer poses a risk of endangerment to USDWs." The Division should include as specifically as possible what is required for this provision to be satisfied (e.g., showing that the CO_2 plume or pressure front has settled or is no longer moving). This showing should also demonstrate that the project no longer poses a risk to public health, safety, or the environment.
Line 687 Reserve3.B(N)(3)	"The Director may approve, in consultation with EPA, an alternative post-injection site care timeframe other than the 50 year default, if an owner or operator can demonstrate during the permitting process that an alternative post-injection site care timeframe is appropriate and ensures non-endangerment of USDWs." It is unclear if "during the permitting process" refers to a specific stage during the lifecycle of an injection facility; it is vital that the review process for any alternative site closure timeline not begin until

	after the Director possesses sufficient data and other evidence from operation of the facility to adequately make this determination. The rule should explicitly identify at what point during a facility's operation the review of an alternative timeframe may occur.

12. Reporting

Line 158 Reserve2.A(F)(6)	"Reports must be made available to the public for inspection and copying on this date." It is unclear whether the EPA or the Division will make these reports publicly available. The Division should retain copies of all reports, and they should be publicly available on an online database maintained by the Division, similar to its current "OCD Online: Imaging" database.
Line 293 Reserve2.E(A)(12)(f)	Permittee is required to report any noncompliance to the Director "which may endanger health or the environment" within 24 hours. These instances of noncompliance are of interest to the public and should be available on a publicly accessible database maintained by the Division.
Lines 639-643 Reserve3.B(L)(3)	With regard to this regulatory section, and in accordance with the language found on line 293, endangerment to public health, safety, and the environment should also be included in 24-hour reporting to the Division by a permittee. These reports should be available on a publicly accessible database maintained by the Division.
Line 648 Reserve3.B(L)(5)	Like the current "OCD Permitting" and "OCD Online: Imaging" databases for oil and gas operations, all reports, submittals, and notifications concerning Class VI wells should be publicly available online and the public should not be required to submit an Inspection of Public Records Act (IPRA) request to obtain them.

13. Local government and consultation

Line 425 Reserve3.B(C)(2)	"The Director shall notify, in writing, any States, Tribes, or Territories within the area of review of the Class VI project based on information provided in paragraphs (1)(b) and (1)(t) of this section of the permit application and pursuant to the requirements at § 145.23(f)(13) of this chapter." This should be more than simple notification and should include meaningful consultation with notified parties; it should also include local governments such as counties and municipalities. Section 1406(d) of Colorado's proposed Class VI rules provides an example of a form that broad notification, participation, and consultation might take.

14. Community outreach

Line 423 Reserve3.B(C)(1)(u)	The draft language requires an owner or operator of a proposed Class VI well to submit, among other items, "A summary of community outreach activities conducted with communities located within the AoR prior to submittal of the permit application;" Minimum requirements should be established for meaningful community outreach. These requirements should be outlined with specificity and should include discrete actions that must be taken by a project applicant. If the Director finds that the project applicant has not fulfilled its duty for meaningful community outreach and consultation, the permit should not be approved until the required outreach and consultation has been undertaken. These provisions likely merit a separate subsection.

15. Emergency response

Line 721 Reserve3.B(O)(2)	Though these provisions are an important foundation, there should be specific minimum requirements for community activities and training for community first responders, including: 1. Training should be ongoing at a prescribed frequency. 2. Emergency materials must be provided in all local languages or presentations given in person with translators present that serve as adequate substitutes for those materials. 3. The specific minimum number and form of "community activities" should be outlined in the rule. 4. Class VI well owners or operators should provide a minimum level of ongoing education and emergency support resources to local government leaders as requested by those leaders and these resources should remain available during the post-injection site care period.
Line 722 Reserve3.B(O)(3)	"If the owner or operator obtains evidence that the injected carbon dioxide stream and associated pressure front may cause an endangerment to a USDW, the owner or operator must:" This language must include endangerment to public health, safety, and the environment alongside endangerment to USDWs. E.g., if the owner or operator obtains evidence that the injected carbon dioxide stream and associated pressure front may cause an endangerment to the public health, safety, environment, or a USDW.
Line 727 Reserve3.B(O)(4)	"The Director may allow the operator to resume injection prior to remediation if the owner or operator demonstrates that the injection operation will not endanger USDWs."

	This language should include "…not endanger public health, safety, the environment" in addition to USDWs. No operations should be resumed at any point during which the operator cannot demonstrate the mechanical integrity of the well in question.
Line 728 Reserve3.B(O)(5)	There must be a mechanism for the local government and community members to participate in any review of an emergency response plan; the operator must solicit feedback/comment from the public as to how the response plan could be improved during each review of such plan.

16. Notice and public hearings

Lines 31, 32 Reserve1(F)(3), (4)	The notice for public hearings and the notice for preparation of draft permits should be extended from 30 days to 60 days. Alternatively, notice should be based upon the types of structures and population present in the Area of Review and any corresponding buffer zone. For example, Section 1406(c) of Colorado's proposed Class VI rules requires: 1) 60 days' notice if the project's working pads would be "within 4,000 feet of a Residential Building Unit, High Occupancy Building Unit, School Facility, or Child Care Center within a Disproportionately Impacted Community"; 2) 45 days' notice if the application includes a proposed location "within ½ mile of a Residential Building Unit, High Occupancy Building Unit, School Facility, or Child Care Center that is not within a Disproportionately Impacted Community" or "Within a Disproportionately Impacted Community"; and 3) 30 days' notice for all other Class VI applications.
Line 33 Reserve1(F)(5)	"Public notice of activities described in paragraph (a)(1) of this section shall be given by the following methods: (1) Electronic mailing (email) *or* by mailing a copy of a notice…" (emphasis added). Notice should be provided by mail *and* email, instead of the current language that provides for either.
Line 33 Reserve1(F)(5)	Notice should also be provided to schools, childcare centers, school governing bodies, police, fire departments, emergency service agencies, and first responder agencies responsible for ensuring public safety within the Area of Review and any corresponding buffer zone. Section 1406(b) of Colorado's proposed Class VI rules provides an example of how broad notice provisions might look.
Line 56 Reserve1(F)(7)	All documents and records concerning a Class VI project, especially those distributed by default, should be accessible to the public without filing an IPRA request and should be posted online for public review.

	This transparency is necessary for the public to be informed and to meaningfully engage during public participation processes.
Lines 57, 58 Reserve1(G), (H)	Line 57: "During the public comment period…any interested person may submit written comments on the draft permit and may request a public hearing, if no hearing has already been scheduled." Line 58: "The Director shall hold a public hearing whenever he or she finds, on the basis of requests, a significant degree of public interest in a draft permit(s)" A public hearing should be held by default and should always be provided for draft permits. Further, a hearing should be provided whenever requested without further finding of public interest by the Director. At minimum, the phrase "significant degree of public interest" is too ambiguous and should be clarified.

17. Fact sheet

Line 17 Reserve1(E)(1)	"The Director shall send this fact sheet to the applicant and, on request, to any other person." The fact sheet for each project should be publicly available without need for request and should be posted on the Division website or on a database maintained by the Division.

18. Mechanical integrity

Line 306 Reserve2.3(A)(15)(c)	"The Director may allow the owner or operator of a well which lacks mechanical integrity pursuant to § 146.8(a)(1) of this chapter to continue or resume injection, if the owner or operator has made a satisfactory demonstration that there is no movement of fluid into or between USDWs." Migration into USDWs is not the only concern and this analysis should consider endangerment to public health, safety, and the environment as well. Further, if a Class VI well lacks mechanical integrity, it should not be permitted to operate until mechanical integrity can be demonstrated.
Line 592 Reserve3.B(J)(4)	The "casing inspection log to evaluate the presence or absence of corrosion or other signs of degradation in the long-string casing" should be mandatory instead of discretionary for all projects at a frequency established by the Division.

19. Testing and monitoring

Line 596 Reserve3.B(K)	Currently, any testing and monitoring plan must be approved by the Director and "[i]t must also include a summary of community engagement activities conducted to develop a plan that addresses project-related risks." As noted in the comment concerning line 423, *supra*, there must be specific minimum community engagement requirements outlined and enforced by the Division with regard to such activities.
Line 612 Reserve3.B(K)(7)(d)	Protection of public health, safety, and the environment would be stronger if surface air monitoring were mandatory like soil gas monitoring. At minimum, surface air monitoring should be mandatory in circumstances or geographic locations that pose special risk to public health, safety, and the environment (e.g., active oil or gas fields and regions home to historic oil or gas fields and infrastructure).
Line 617 Reserve3.B(K)(8)(a)	Seismicity monitoring plans must be based on the potential risk to public health, safety, and the environment in addition to the potential danger to USDWs within the Area of Review.
Line 620 Reserve3.B(K)(10)	"An initial review of the testing and monitoring plan shall occur two years after injection begins, and at no time may exceed four years." Testing and monitoring plans should be reviewed after the first year of operation and should continue to be reviewed every two years thereafter; there should not be an upper permissible limit of review every four years.

20. Area of Review

Line 73 Reserve1(A)(4)	The rule would provide more protection to USDWs, the public, and the environment if a minimum Area of Review was set, at least ¼ mile from the project as a default, with this radius extending further than ¼ mile as required by calculation of the "zone of endangering influence.".
Lines 379, 442 Reserve3.B(B)(1), Reserve3.B(E)(1)	The definition of "Area of review" should encompass the region surrounding a geologic sequestration project within which public health, safety, or the environment, in addition to USDWs, could be endangered.
Lines 446, 458 Reserve3.B(E)(2)(b), Reserve3.B(E)(5)	"The fixed frequency between AoR reevaluations, which must include an initial reevaluation two years after injection begins, and at no time may exceed four years" The frequency of Area of Review reevaluations should include an initial review after the first year and remain set at once every two years

	thereafter; the frequency should not be relaxed to allow for review once every four years.
Line 464 Reserve3.B(E)(7)	"All modeling inputs and data used to support area of review reevaluations under paragraph (5) of this section shall be retained for 10 years *after site closure*." (emphasis in original) Data and modeling used to support initial Area of Review evaluations and determinations should be publicly available as part of the application process for a project; data and modeling used in subsequent revaluations should be available for review upon request.

21. Transfers

Line 225 Reserve2.D(F)(2)	"Automatic transfers of permits shall be prohibited unless approved by the Director." Automatic transfers should always be prohibited. Even as worded, the rule contemplates that an "automatic" transfer should be subject to the approval of the Director. As such, automatic transfers are unnecessary.
Lines 224, 225 Reserve2.D(F)(1), Reserve2.D(F)(2)	These two provisions appear to be the primary two provisions regulating transfer of a Class VI permit. The rule should include detailed provisions regulating transfer of Class VI wells and providing safeguards to ensure transferee resources to operate, maintain, and close wells and to prevent issues with improper well abandonment. As noted in the comment regarding lines 257, 258, 260, *supra*, a well transfer may be better classified as a major modification than a minor modification in the Class VI context. There is currently a lack of clarity as to what factors, if any, must be weighed by the Director's in coming to a decision to approve or deny a well transfer.

22. Records

Line 278 Reserve2.E(A)(10)(b)(ii)	As written, the Director *may* require an operator to provide monitoring records to the Division after the three-year mandatory monitoring period passes. It should be mandatory for the Division to request these records and the Division should retain electronic copies of monitoring records indefinitely, as the State will eventually assume all ongoing site monitoring and care obligations for the well in perpetuity.
Lines 651, 653 Reserve3.B(L)(6)(b) and (d)	"Data on the nature and composition of all injected fluids" and "[w]ell plugging reports, post-injection site care data" should be delivered to the Division and should be retained indefinitely because the State will become responsible for all ongoing site monitoring and care obligations in perpetuity.

Line 668 Reserve3.B(M)(4)	For the reasons stated in the comments concerning lines 278, 651, and 653, *supra*, the Division should retain electronic copies of the well plugging report indefinitely.
Line 711 Reserve3.B(N)(6)	For the reasons stated in the comments concerning lines 278, 651, and 653, *supra*, the Division should retain electronic copies of the site closure report indefinitely.
Line 719 Reserve3.B(N)(8)	For the reasons stated in the comments concerning lines 278, 651, and 653, *supra*, the Division should retain electronic copies of the records collected during the post-injection site care period indefinitely.

23. Inactive wells

General	The Division must include language regulating "inactive," "idle," and/or "temporarily abandoned" Class VI wells to allow for their identification and to prevent such wells from becoming State liabilities prior to the Division's assumption of responsibility for the wells. As noted in the comment concerning line 303, *infra*, the use of the term "temporary or intermittent cessation of injection" is used in the rule but is not defined or further clarified. Any temporary cessation of injection must be tightly regulated to protect the State, and any longer cessation of injection should result in additional proactive protective measures by the Division.
Line 303 Reserve2.E(A)(15)	The term "temporary or intermittent cessation of injection" is used in the draft rule but it is not defined or further clarified. This language reinforces the need to include provisions in the rule governing "inactive," "idle," or "temporarily abandoned" wells.

24. Unitization and ownership

General	It does not appear that the Division has the authority to institute any unitization regime. The authority for such regulation with regard to Class VI projects might have been granted by HB 457, but that bill did not pass during the 2025 legislative session.
Reserve4(D)(1), pgs. 262-263	"All carbon dioxide injected into geologic sequestration in a sequestration unit shall be deemed the property of the operator. During the term of the sequestration unit and for so long as the sequestration unit agreement remains in force and effect, no surface or mineral interest owner or lessee shall have the right to produce, capture, take, reduce to possession, waste or otherwise interfere with or exercise any control over such carbon dioxide within the sequestration unit unless approved by the operator and the division or except as to drilling operations through the formation subject to the sequestration unit for purposes of drilling to deeper depths and horizons for the extraction of oil, gas and other minerals."

	It is unclear whether the Division has the authority to create a new property interest in injected CO_2 absent statutory authority. This language appears to come directly from the text of HB 457, which did not pass during the 2025 legislative session. If there were such authority, the rule would be stronger if it outlined a process and minimum requirements for "drilling operations through the formation subject to the sequestration unit for purposes of drilling to deeper depths and horizons for the extraction of oil, gas and other minerals." Any drilling through a sequestration zone must be highly regulated by the Division to prevent leakage, endangerment and ensure the confining zone is not compromised.

WildEarth Guardians

Exhibit 4

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

October 28, 2022

OFFICE OF THE
CHIEF FINANCIAL OFFICER

The Honorable Chellie Pingree
Chair, Subcommittee on Interior,
Environment, and Related Agencies
Committee on Appropriations
House of Representatives
Washington, D.C. 20515

The Honorable David Joyce
Ranking Member, Subcommittee on Interior,
Environment, and Related Agencies
Committee on Appropriations
House of Representatives
Washington, D.C. 20515

The Honorable Jeff Merkley
Chair, Subcommittee on Interior,
Environment, and Related Agencies
Committee on Appropriations
United States Senate
Washington, D.C. 20510

The Honorable Lisa Murkowski
Ranking Member, Subcommittee on Interior,
Environment, and Related Agencies
Committee on Appropriations
United States Senate
Washington, D.C. 20510

Dear Chairs and Ranking Members:

Enclosed is the U.S. Environmental Protection Agency's Report to Congress regarding recommendations to improve Class VI permitting procedures for commercial and research carbon sequestration projects. This report is provided as directed by the Explanatory Statement accompanying the Consolidated Appropriations Act, 2021 (Public Law 116-260), which states the following:

> *Water: Human Health-The agreement provides $108,487,000 for Water: Human Health. The Committees direct the Agency to maintain the Beach/Fish program project at the enacted level. Of the increase provided, $1,000,000 is to further support implementation of requirements under America's Water Infrastructure Act of 2018 (Public Law 115-270). Within available funds, not less than $3,000,000 is for the Agency's work within the Underground Injection Control program related to Class VI wells for geologic sequestration to help develop expertise and capacity at the Agency. These funds should be used by the Agency to review and process Class VI primacy applications from States and Tribes and to directly implement the regulation, where States have not yet obtained primacy by working directly with permit applicants. Additionally, the Agency is directed to submit a report, and provide a briefing to the Committees, not later than one year after enactment of this Act on recommendations to improve Class VI permitting procedures for commercial and research carbon sequestration projects. The report should be drafted in consultation with the Department of Energy, relevant State agencies, previous permit applicants, and nongovernmental stakeholders.*

This report provides background information on Class VI wells, outlines permitting regulations, explains the EPA's permit application and review process, summarizes feedback the agency has received from stakeholders about the process, and describes actions the EPA is currently taking in response to stakeholder feedback.

If you have further questions or you would like to set up a meeting to discuss this report, please contact Ed Walsh at (202) 564-4594 or walsh.ed@epa.gov.

Sincerely,

Amin, Faisal

Digitally signed by Amin, Faisal
Date: 2022.10.28 14:12:51 -04'00'

Faisal Amin
Chief Financial Officer

Enclosure

EPA Report to Congress: Class VI Permitting

October 2022

Class VI Permitting Report to Congress

1. Introduction

Climate change is one of the most complex issues facing us today. Carbon Capture, Utilization, and Sequestration (CCUS) refers to technologies that capture carbon dioxide from an emissions source, such as a power plant, and permanently store the carbon, such as through deep well injection in a permitted Class VI Underground Injection Control (UIC) well (known as geologic sequestration). To reach the President's ambitious domestic climate goal of net-zero emissions, economy-wide, by 2050, the United States will likely have to capture, transport, and permanently sequester significant quantities of carbon dioxide (CEQ, 2021). The successful widespread deployment of responsible CCUS, as well as carbon dioxide removal (CDR) approaches (e.g., direct air capture and sequestration, bioenergy generation with carbon capture and sequestration), will require strong and effective permitting and efficient regulatory regimes to safeguard public health and the environment with meaningful public engagement. The U.S. Environmental Protection Agency's (EPA's) Class VI regulations, which are a part of the U.S. regulatory regime for CCUS[1] and will be required for the geologic sequestration components of CDR approaches, are essential for geologic sequestration deployment that is protective of underground sources of drinking water (USDWs) and human health.

Interest in CCUS and in the Class VI permit program has increased dramatically after passage of enhancements to a tax credit for carbon sequestration in 2018. Since that time, EPA has met with more than 100 companies and other interested parties to discuss questions and concerns around geologic sequestration and the Class VI permitting program and EPA expects this level of interest to continue.

This report provides background on Class VI wells, outlines permitting regulations, explains EPA's permit application and review process, summarizes feedback EPA has received from stakeholders about the process, and describes actions EPA is currently taking in response to stakeholder feedback. UIC primary enforcement authority (primacy) (i.e., when a state, Tribe, or territory applies to EPA to be the permitting authority for UIC wells and receives that authority within their state, Tribe, or territory) also is briefly discussed herein. However, specific details related to requirements for Class VI primacy applications and EPA's review and approval of Class VI primacy applications are outside the scope of this report.

1.1 Overview of Congressional Request

In an effort to better understand the issues surrounding the Class VI program, on December 27, 2020, the U.S. Congress enacted Division G, Department of the Interior, Environment, and Related Agencies, of the Consolidated Appropriations Act, 2021. The Explanatory Statement

[1] For a complete picture of the U.S. CCUS regulatory regime, see Appendix A of *Council on Environmental Quality Report to Congress on Carbon Capture, Utilization, and Sequestration* (CEQ, 2021) available at: https://www.whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf.

that accompanies the Act directed EPA to: "submit a report and provide a briefing to the Committees not later than one year after enactment of this Act on recommendations to improve Class VI permitting procedures for commercial and research carbon sequestration projects." The Explanatory Statement further stipulated that: "the report should be drafted in consultation with the Department of Energy, relevant State agencies, previous permit applicants, and nongovernmental stakeholders." This report was written to respond to this request and focuses on the UIC Class VI regulations and permitting process.

This report is one in a series of reports on CCUS requested by Congress as part of the Consolidated Appropriations Act, 2021. Highlighted below are those Congressionally mandated reports particularly relevant to this report.

- Utilizing Significant Emissions with Innovative Technologies (USE IT) Act (Division S of the Consolidated Appropriations Act of 2021):
  - A report to Congress on deep saline formations focusing on the risks and benefits of geologic sequestration (GS) with recommendations for risk management and mitigation (Congress directed EPA to lead this report)
  - A National Academies of Sciences, Engineering, and Medicine study to assess the barriers and opportunities relating to the commercial application of carbon dioxide (CO_2) (Congress directed the U.S. Department of Energy (DOE) to lead this report and collaborate with EPA)
  - A report to Congress that identifies and inventories existing relevant federal permitting information and resources for CCUS stakeholders, initiatives, and recent publications on CO_2 pipeline needs, gaps in the current regulatory framework, federal financial mechanisms available to project developers, and public engagement opportunities through existing laws (Congress directed the White House Council on Environmental Quality (CEQ) to lead this report and collaborate with EPA and other federal agencies)

- Energy Act of 2020 (Division Z of the Consolidated Appropriations Act, 2021):
  - A National Academies of Sciences, Engineering, and Medicine study to assess any barriers and opportunities relating to commercializing carbon, coal-derived carbon, and CO_2
  - A Government Accountability Office report on the successes, failures, practices, and improvements of DOE in carrying out commercial-scale carbon capture demonstrations
  - A report to Congress on the carbon capture technology program
  - A report to Congress that assesses the progress of all regional carbon sequestration partnerships, identifies the remaining challenges in achieving large-scale carbon sequestration, and creates a roadmap for carbon storage

- A report to Congress examining the opportunities for research and development in integrating blue hydrogen technology in the industrial power sector and how that could enhance the deployment and adoption of CCUS
- A report to Congress on CO_2 removal methods

On June 30, 2021, CEQ issued a report to Congress that identified and inventoried existing relevant federal permitting information and resources for CCUS stakeholders, initiatives, and recent publications on CO_2 pipeline needs, gaps in the current regulatory framework, federal financial mechanisms available to project developers, and public engagement opportunities through existing laws as congressionally mandated in the USE IT Act (CEQ, 2021).[2] The CEQ report provides important background on the role of CCUS in addressing climate change and the state of technologies, policies, and permitting related to CCUS that may be helpful for readers. Additionally, on February 16, 2022, CEQ published a draft Carbon Capture, Utilization, and Sequestration Guidance with a request for public comment (closed April 18, 2022).[3] Consistent with the USE IT Act, CEQ issued the guidance to facilitate reviews associated with the deployment of CCUS and to promote the efficient, orderly, and responsible development and permitting of CCUS projects at an increased scale in line with the Administration's climate, economic, and public health goals (CEQ, 2022).

1.2 Carbon Capture, Utilization, and Storage Background Information

CCUS refers to a set of technologies that capture CO_2 from emission sources and either transport, compress, and inject it deep in the earth's subsurface or transform it for utilization in industrial processes or as feedstock for useful commercial products. GS is a component of CCUS related to the underground injection and long-term containment of CO_2.

CO_2 is first captured from one or more emission source(s). To transport captured CO_2 to a GS site, operators typically compress CO_2 to convert it from a gaseous state to a supercritical fluid. CO_2 exists as a supercritical fluid at high pressures, and, in this state, the CO_2 exhibits properties of both a liquid and a gas. After capture and compression, the CO_2 is delivered to the GS site, frequently by pipeline, or alternatively using tanker trucks or ships. When injected into a suitable geologic formation, CO_2 is sequestered by a combination of trapping mechanisms, including physical and geochemical processes. Physical trapping can occur when the CO_2 reaches a geologic zone of low permeability or when residual CO_2 is immobilized in formation pore space due to capillary forces. Geochemical trapping occurs when chemical reactions between the dissolved CO_2 and minerals in the formation lead to the precipitation of solid carbonate minerals. The timeframe over which CO_2 will become trapped by these mechanisms depends on properties of the receiving formation and the injected CO_2 stream (75 FR 77230; US EPA, 2010).

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[2] The CEQ report *Council on Environmental Quality Report to Congress on Carbon Capture, Utilization, and Sequestration* is available at: https://www.whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf.

[3] Draft CEQ guidance, *Carbon Capture, Utilization, and Sequestration Guidance* (CEQ, 2022) available at: https://www.federalregister.gov/documents/2022/02/16/2022-03205/carbon-capture-utilization-and-sequestration-guidance.

The injection of large volumes of CO_2 into the subsurface involves a complex suite of technologies that spans several technical and scientific disciplines. The technologies for CCUS already exist, with a reported 26 commercial-scale projects in operation globally, and an estimated 45 CCUS facilities in operation or in development in the United States today (CEQ, 2021). Current GS projects reflect the development or adaptation of technologies related to geology, geochemistry, and hydrology for site characterization; well engineering for construction, testing, and logging; modeling and reservoir simulation for area of review (AoR)[4] delineations; chemical and geophysical-based measurement, monitoring, and verification technologies; and risk assessment. Much of this research has been led by the federal government, including by DOE. DOE has invested more than $1 billion during the past two decades through its Carbon Storage Research and Development (R&D) Program to develop the technologies and capabilities for widespread commercial deployment of geologic storage, including research projects that have injected 11–12 million tons of CO_2. This investment has made the United States a leader in this worldwide effort. Federal government research on GS includes research on GS and risk management (see, e.g., *Overview of Potential Failure Modes and Effects Associated with CO_2 Injection and Storage Operations in Saline Formations* (Warner et al., 2020) and NETL's *Safe Geologic Storage of Captured Carbon Dioxide: Two Decades of Doe's Carbon Storage R&D Program on Review* (NETL, 2020)); the U.S. Department of Interior (see, *Report to Congress: Framework for Geological Carbon Sequestration on Public Land* (U.S. Department of the Interior, 2009); and EPA (see, *Vulnerability Evaluation Framework for GS of Carbon Dioxide* (US EPA, 2008)).

[4] Per 40 CFR 146.84(a), the area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected CO_2 stream and is based on available site characterization, monitoring, and operational data.

The Intergovernmental Panel on Climate Change has identified CCUS and CDR as essential tools to limit warming to 1.5°C, in addition to achieving deep reductions in greenhouse gas emissions (IPCC, 2022). CCUS projects, including GS projects, will only deliver desired societal and environmental benefits if they are well designed and well governed.

2. UIC Class VI Regulations

The Safe Drinking Water Act (SDWA) directed EPA to develop regulations that prevent underground injection activities from endangering drinking water sources. EPA developed the UIC regulations to ensure underground injection wells are constructed, operated, and closed in a manner that is protective of USDWs and address potential risks to USDWs associated with injection activities. The UIC regulations address the major pathways by which injected fluids can migrate into USDWs, including along the injection well bore, via improperly completed or plugged wells in the AoR of the injection well, direct injection into a USDW, faults or fractures in the confining strata, or lateral displacement into hydraulically connected USDWs (see Figure 1).

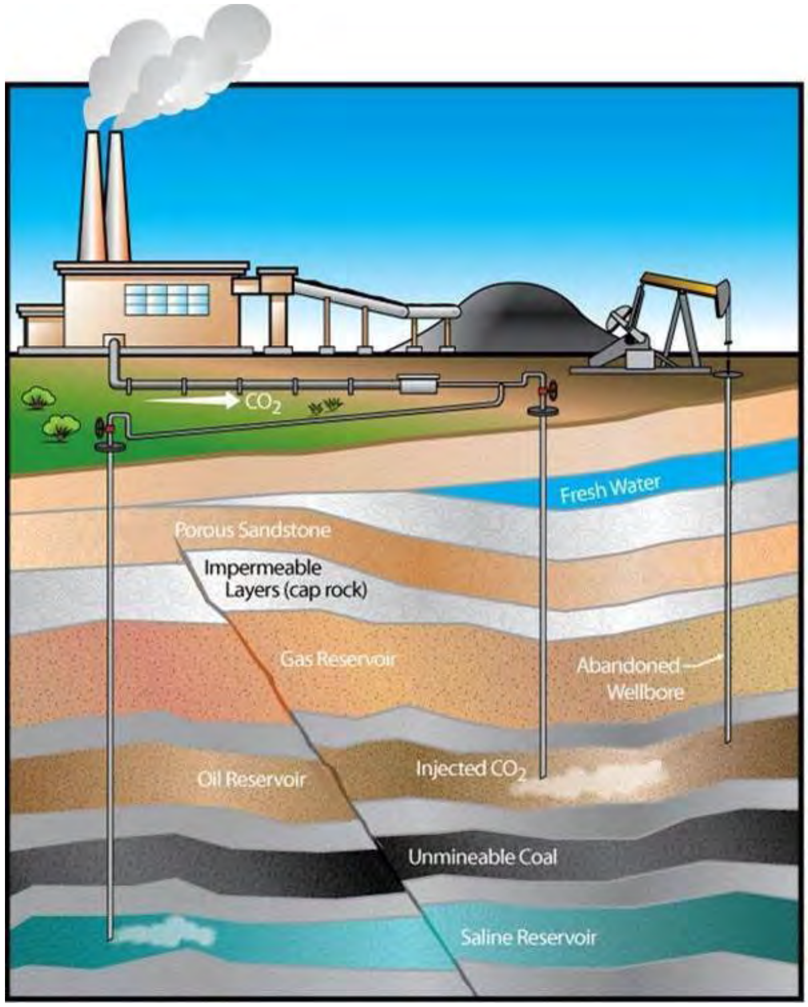

Figure 1. Schematic of CO_2 injection for geologic sequestration. (Source: LBNL)

States may apply to EPA to be the UIC permitting authority in the state and receive primary enforcement authority (primacy). Where a state has not obtained primacy, EPA is the UIC permitting authority. When the UIC regulations were first codified in 1980, the UIC Program defined five classes of injection wells and set regulations for each well class based on the risks posed by the specific injection activities (see Figure 2).

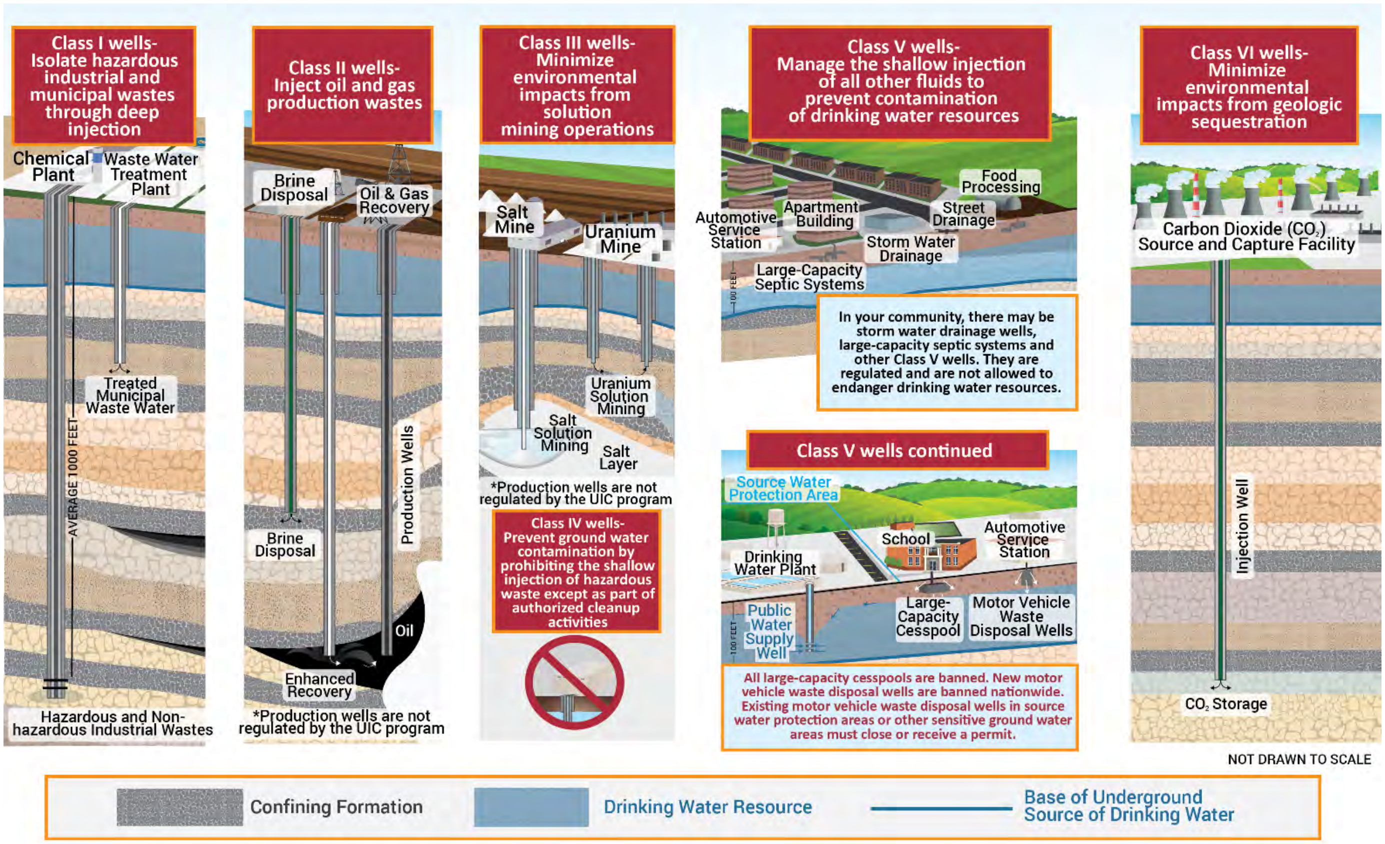

Figure 2. UIC injection well classes. Injection well Classes I, II, III, IV, and V were established as part of EPA's 1980 UIC rulemaking, and through a subsequent 1999 Class V addition. EPA established well Class VI in a 2010 rulemaking.

Recognizing that CO_2 injection, for the purpose of GS, poses unique risks relative to other injection activities, EPA promulgated *Federal Requirements Under the UIC Program for Carbon Dioxide GS Wells* (75 FR 77230; US EPA, 2010), known as the Class VI Rule, in December 2010. The rule created and set requirements for a new class of injection wells, Class VI. The Class VI Rule builds upon the long-standing protective framework of the UIC Program, with requirements that are tailored to address issues unique to large-scale GS, including large injection volumes, higher reservoir pressures relative to other injection formations, the relative buoyancy of CO_2, the potential presence of impurities in captured CO_2,[5] the corrosivity of CO_2 in the presence of water, and the mobility of CO_2 within subsurface geologic formations. These additional protective requirements include more extensive geologic testing, detailed computational modeling of the AoR and periodic re-evaluations, detailed requirements for

[5] Impurities may include incidental amounts of associated substances derived from the source materials and the capture process and any substances added to the stream to enable or improve the injection process. The composition of these substances varies by the emissions source. Any CO_2 stream that meets the definition of a hazardous waste, under 40 CFR part 261, must be injected into a UIC Class I hazardous waste injection well (see Figure 2).

monitoring and tracking the CO_2 plume and pressure front,[6] unique financial responsibility requirements, and extended post-injection monitoring and site care.

Throughout the rulemaking process for the Class VI Rule, EPA engaged with states, Tribes, and stakeholders, including those from industry, environmental groups, utilities, academia, and the public, to understand their concerns and solicit technical feedback. EPA also conducted a series of technical workshops to identify and discuss questions regarding the effective management of CO_2 injection, including site characterization, AoR modeling, testing and monitoring, well construction, and mechanical integrity testing. EPA also held public meetings on the rulemaking.

Overview of the Federal Class VI Rule Requirements

Permit information requirements establish the material that owners or operators must submit to obtain a Class VI permit [40 CFR 146.82].

Minimum criteria for siting require Class VI wells to be located in areas with a suitable geologic system, including an injection zone that can receive the total anticipated volume of CO_2 and a confining zone(s) to contain the injected CO_2 stream and displaced formation fluids [40 CFR 146.83].

AoR and corrective action provisions require delineation of the AoR for proposed Class VI wells using computational modeling. Additionally, these provisions require the preparation of a Corrective Action plan and implementation of the plan.[7] A Class VI well owner or operator must periodically reevaluate the AoR and amend the plan, if necessary [40 CFR 146.84].

Financial responsibility requirements establish that owners or operators must demonstrate and maintain sufficient funds to perform necessary corrective action on existing wells within the AoR (e.g., any wells determined to potentially cause leakage of injected CO_2 or formation fluid), plug the injection well, perform post-injection site care (PISC) and site closure[8] activities, and complete any necessary emergency and remedial response activities [40 CFR 146.85].

Injection well construction requirements specify the design and materials used in the construction of Class VI wells. To prevent the endangerment of USDWs, only materials compatible with the CO_2 stream, over the duration of the GS project, are permitted [40 CFR 146.86].

[6] The pressure front of a CO_2 plume refers to the zone where there is a pressure differential sufficient to cause the movement of injected fluids or formation fluids into a USDW (U.S. EPA, 2010).
[7] Corrective action means the use of Director-approved methods to ensure that wells within the area of review do not serve as conduits for the movement of fluids into USDWs.
[8] Site closure means the point/time, as determined by the Director following the requirements under 40 CFR 146.93, at which the owner or operator of a geologic sequestration site is released from post-injection site care responsibilities.

Requirements for logging, sampling, and testing prior to operation outline activities, including logs, surveys, and tests of the injection well and formations, that must be performed before injection of CO_2 may commence [40 CFR 146.87].

Operating requirements outline operational measures for Class VI wells to ensure that the injection of CO_2 does not endanger USDWs. As important, these provisions establish limitations on injection pressure and requirements for automatic shut-off devices [40 CFR 146.88]. The mechanical integrity requirements specify continuous monitoring to demonstrate internal mechanical integrity and annual external mechanical integrity tests [40 CFR 146.89].

Testing and monitoring requirements define the elements that must be included in the required Testing and Monitoring Plan submitted with a Class VI permit application. The testing and monitoring must be conducted throughout the project life, until site closure, to demonstrate the safe operation of the injection well (e.g., through mechanical integrity testing of the well) and track the position of the CO_2 plume and pressure front (e.g., through groundwater monitoring) [40 CFR 146.90].

Reporting requirements establish the timeframes and circumstances for the electronic submission of Class VI well testing, monitoring, and operating results and requirements for keeping records [40 CFR 146.91].

Injection well plugging requirements specify that a Class VI injection well must be properly plugged to ensure that the well does not become a conduit for fluid movement into USDWs in the future [40 CFR 146.92].

PISC and site closure requirements address activities that occur following cessation of injection. The owner or operator must continue to monitor the site for a default 50 year period following the cessation of injection or, if approved by the Director, for an alternative timeframe, until it can be demonstrated that no additional monitoring is needed to ensure that the project does not pose an endangerment to USDWs; following this, the owner or operator must plug the injection and monitoring wells and close the site [40 CFR 146.93].

Emergency and remedial response requirements specify that owners or operators of Class VI wells must develop and maintain an approved Emergency and Remedial Response Plan that describes the actions to be taken to address events that may cause endangerment to a USDW [40 CFR 146.94].

Class VI injection depth waiver requirements provide a process under which Class VI well owners or operators can seek a waiver from the injection depth requirements in order to inject CO_2 into non-USDWs that are located above or between USDWs [40 CFR 146.95].

Section 2.1 presents information on materials that EPA developed to support the Class VI regulations.

2.1 Class VI Rule Support Documents

From 2011 to 2018, EPA finalized and published a series of tools and other resources to support Class VI well permit applicants, owners and operators, and permitting authorities in understanding and implementing the requirements of the Class VI Rule.

EPA's guidance documents provide recommendations and considerations for Class VI well operators and UIC permitting authorities on meeting the requirements of the Class VI Rule. Elements included in EPA guidance documents cannot be enforced as regulatory requirements unless EPA is explicitly citing rule requirements.

Guidance documents for owners or operators address the following technical topics:

- Geologic site characterization[9]
- AoR evaluation and corrective action[10]
- Financial responsibility[11]
- Well construction[12]
- Testing and monitoring[13]
- Reporting and record keeping[14]
- Required Class VI Project Plans[15]
- Well plugging, PISC, and site closure[16]

Guidance documents for states/permitting authorities include:

- The Class VI Implementation Manual, which describes recommended activities to support the review and evaluation of Class VI project information[17]
- A Primacy Manual that provides procedural support for preparing UIC primacy

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[9] *Geologic Sequestration of Carbon Dioxide – UIC Program Class VI Well Site Characterization Guidance* (US EPA, 2013a)
[10] *Geologic Sequestration of Carbon Dioxide – UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance* (US EPA, 2013b)
[11] *Geologic Sequestration of Carbon Dioxide – UIC Program Class VI Financial Responsibility Guidance* (US EPA, 2011a)
[12] *Geologic Sequestration of Carbon Dioxide – UIC Program Class VI Well Construction Guidance* (US EPA, 2012a)
[13] *Geologic Sequestration of Carbon Dioxide – UIC Program Class VI Well Testing and Monitoring Guidance* (US EPA, 2013c)
[14] *Geologic Sequestration of Carbon Dioxide, UIC Program Class VI Reporting, Record-keeping, and Data Management Guidance for Owners or Operators* (US EPA, 2016a)
[15] *Geologic Sequestration of Carbon Dioxide – UIC Program Class VI Well Project Plan Development Guidance* (US EPA, 2012b)
[16] *Geologic Sequestration of Carbon Dioxide, UIC Program Class VI Well Plugging, Post-Injection Site Care, and Site Closure Guidance* (US EPA, 2016b)
[17] *Geologic Sequestration of Carbon Dioxide – UIC Program Class VI Implementation Manual for UIC Program Directors* (US EPA, 2018)

application materials[18]
- A 2015 Memorandum from EPA's Office of Ground Water and Drinking Water to Regional Water Division Directors, Key Principles in EPA's UIC Program Class VI Rule Related to the Transition of Class II Enhanced Oil or Gas Recovery Wells to Class VI[19]

EPA also developed a set of quick reference guides to support permitting authorities on the following topics:

- Incorporating environmental justice (EJ) considerations into the Class VI permitting process[20]
- Public participation[21]
- Interstate coordination[22]

To support the electronic reporting requirement of the Class VI Rule at 40 CFR 146.91(e), EPA collaborated with the Pacific Northwest National Laboratory (PNNL) to develop the Geologic Sequestration Data Tool (GSDT).[23] The GSDT is a centralized, web-based system that receives, stores, and manages Class VI data and also can support permitting authorities in enforcement and program oversight activities such as organizing and retaining the large volume of material related to Class VI permit applications.

3. Class VI Permitting

Class VI projects involve several phases (see Figure 3). They include:

- **Pre-permitting phase.** The prospective owner or operator prepares the Class VI permit application and is encouraged to meet with the permitting authority to discuss the permitting process.
- **Pre-construction phase.** The prospective owner or operator submits a Class VI permit application, which the permitting authority will review and, if appropriate, issue a Class VI permit for the injection well.
- **Pre-operation phase**. The Class VI well owner or operator submits the results of required pre-operational testing, updated information about site geology, the final AoR,

[18] *Geologic Sequestration of Carbon Dioxide – UIC Program Class VI Primacy Manual for State Directors* (US EPA, 2014)
[19] *Key Principles in EPA's Underground Injection Control Program Class VI Rule Related to Transition of Class II Enhanced Oil or Gas Recovery Wells to Class VI* (US EPA, 2015)
[20] *Geologic Sequestration of Carbon Dioxide – UIC Quick Reference Guide - Additional Tools for UIC Program Directors Incorporating Environmental Justice Considerations into the Class VI Injection Well Permitting Process* (US EPA, 2011b)
[21] *Geologic Sequestration of Carbon Dioxide – UIC Quick Reference Guide - Additional Considerations for UIC Program Directors on the Public Participation Requirements for Class VI Injection Wells* (US EPA, 2011c)
[22] *Geologic Sequestration of Carbon Dioxide – UIC Quick Reference Guide - Additional Considerations for UIC Program Directors on the Interstate Coordination Requirements for the Class VI Injection Well Permitting Process* (US EPA, 2011d)
[23] https://epa.velo.pnnl.gov/

any needed amendments to the Project Plans, and information about the construction and testing of the well. This phase ends when the permitting authority issues the Class VI permit holder authorization to inject CO_2 into the well.

- **Injection phase**. Class VI well owners or operators conduct injection activities, perform testing and monitoring, and reevaluate the AoR, as described in the Class VI permit and Project Plans.
- **Post-injection phase.** The Class VI well owner or operator plugs the injection well, monitors the CO_2 plume and pressure front, and, after demonstrating USDW non-endangerment, closes the site.

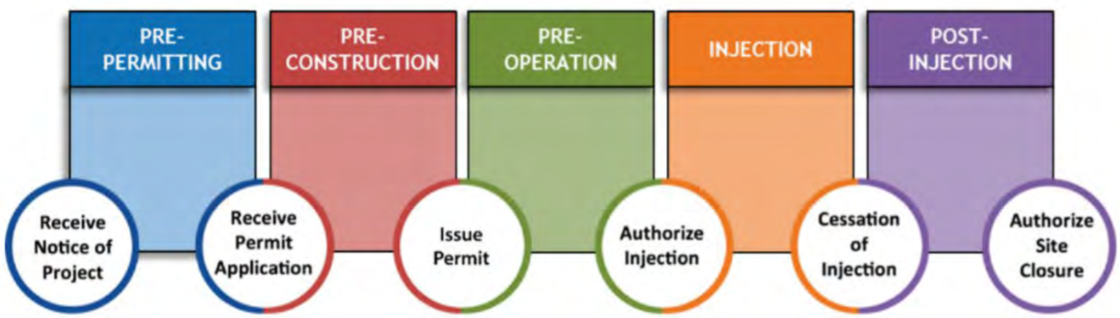

Figure 3. The Phases of a Class VI Project.

Section 3.1 provides additional information related to the permit application process for Class VI well owners and operators and Section 3.2 describes EPA's permit application review process and permit issuance process. EPA is the permitting authority for Class VI wells in all states except where a state, Tribe, or territory has applied for and received primacy for UIC Class VI wells. The Class VI regulations in primacy states, Tribes, and territories must be approved by EPA and must be as stringent as the Federal Class VI regulations. EPA maintains oversight responsibility for approved UIC primacy programs. However, processes for Class VI permit application, review, and issuance may be different in states, Tribes, or territories with Class VI primacy. As of the writing of this report, the States of Wyoming and North Dakota have Class VI primacy.

3.1 Overview of the Class VI Permitting Process

Class VI permit applicants must apply for a permit for each Class VI well they plan to operate. Permit applications are detailed and contain information about the geologic conditions at the proposed site, computational modeling of the AoR around the injection well, the construction of the injection well, planned operation/injection and post-injection phase testing and monitoring, financial responsibility, and emergency response planning. This information is typically submitted as a permit application narrative and a set of required Project Plans and related information such as maps, geologic cross sections, modeling data files, engineering schematics, and financial documents also are submitted. Permit application materials are submitted via the GSDT where EPA is the permitting authority for Class VI wells (states with Class VI primacy may elect to use the GSDT). During the permitting authority's review of the permit application, the applicant may be asked to provide additional information to answer questions about the review or clarify the information in the permit application.

Once the final Class VI permit has been issued by the permitting authority, the permittee is authorized to construct or convert (if the intended injection well was previously constructed to Class VI well standards, but permitted or used for a different purpose) the injection well and perform required pre-operational testing. The permittee must follow these steps and submit testing results and any other information stipulated in the final permit to the permitting authority. The permittee must wait for the permitting authority to issue an Authorization to Inject before CO_2 injection can commence.

Although there is limited data on Class VI permitting timeframes specifically, information on other well classes is pertinent. For example, Class I is similar to Class VI based on regulatory structure, including the amount of site-specific data required as part of the permit application. Since 2019, EPA has issued 25 new Class I permits. The processing time (measured from receipt of permit application to permit issuance) was typically less than two years. EPA anticipates that prospective owners or operators submitting complete Class VI applications will be issued permits in approximately two years. Factors that may impact permitting timeframes include the quality and quantity of site-specific data submitted by the applicant, the amount of time the applicant takes to respond to requests for additional information from the permitting authority, and the number and complexity of public comments received on the draft permit.

3.2 Permit Application Reviews

Review of a Class VI permit application by the permitting authority entails a multidisciplinary evaluation to determine whether the application includes the required information, is technically accurate, and supports a risk-based determination that USDWs will not be endangered by the proposed injection activity.

The permit application review necessitates a team approach—involving subject matter experts in geology, hydrology/hydrogeology, modeling, well engineering, finance, and risk analyses—to collectively review the topics addressed in the application. EPA works to ensure a scientifically rigorous and efficient process in reviewing permit applications. The EPA Region where the project will be located has the lead for the permit application review, communicating with the applicant, and issuing permitting decisions, in coordination with other EPA components, as well as federal, state, Tribal, and local entities, as appropriate. A permit application review involves the following activities:

- **Completeness review.** The first step of this review is determining that the permit application is complete (i.e., that it contains all of the information required at 40 CFR 146.82(a)). If any required information is missing, the permitting authority requests it from the applicant.
- **Technical review**. Following a completeness determination, a technical review of each element of the permit application commences. The technical review focuses on evaluating the geologic and hydrogeologic information to confirm site suitability (i.e.,

that the proposed project site can receive and store the total volume of CO_2 to be injected over the life of the project). This geologic information, in turn, supports a thorough review of the AoR delineation modeling effort to confirm that an appropriately robust model was used, the model inputs and assumptions are consistent with available geologic information, and the results accurately represent the area over which the CO_2 plume and pressure front are anticipated to expand during injection operations. The modeling results will then inform an evaluation of the adequacy of the testing and monitoring plan and the proposed PISC timeframe. Engineering evaluations of the injection and monitoring wells ensure that they will be designed, constructed, tested, and plugged in a manner that will not endanger USDWs. Financial assurance and risk reviews also are performed to verify that procedures and adequate financial resources are available to respond to unanticipated events, such as a leak in the well casing.

Throughout the review, as questions arise, they are posed to the applicant via formal requests for additional information (RAIs). The permitting authority stipulates a timeframe for response in the RAI, which will depend on the nature of the missing information. It is important for the applicant to provide the missing information in a timely manner so as not to extend the overall time for the review.

- **Considerations under federal law.** Along with the technical review, EPA will conduct reviews required under other relevant federal requirements and policies for EPA-issued permits. This includes Presidential Executive Order 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations* (59 FR 7269, Feb. 16, 1994), which states that Federal Agencies "shall make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations." The EPA UIC program completes an EJ review using EPA's EJScreen Tool, an online mapping tool that integrates numerous demographic, socioeconomic, and environmental data sets that are overlain on the delineated AoR to identify whether any portions of the AoR encompass disadvantaged communities. If the results indicate a potential EJ impact, permit writers consider potential permitting measures to mitigate the impacts of the Class VI project on those communities and enhance the public participation process to be inclusive of all potentially affected communities (e.g., conduct early targeted outreach to communities and identify and mitigate any communication obstacles such as language barriers or lack of technology resources). Other federal laws that may apply to EPA issuance of UIC permits and must be considered are listed in the U.S. Code of Federal Regulations at 40 CFR 144.4.
- **Draft permit package, public notice draft permit, and issue final permit.** Once a permitting authority determines that a permit application meets the requirements of the Class VI Rule, the permitting authority issues a Class VI draft permit for public comment. The permit package consists of the draft UIC permit, Class VI Project Plans (for AoR and Corrective Action, Testing and Monitoring, Injection Well Plugging, Post-Injection Site Care, and Emergency and Remedial Response); a summary of operating

requirements; well construction details; financial responsibility information; and a well stimulation program.

The draft UIC permit must be issued for public comment with a minimum public comment period of 30 days (required by 40 CFR 124.10(b)). The permitting authority issuing the permit also will hold a public hearing if one is requested during the comment period or may elect to schedule a public hearing if significant public interest is anticipated.

Following consideration of comments received, the permitting authority modifies and issues a final permit, as appropriate. A final permit authorizes the applicant to construct or convert the injection well and any new monitoring wells and perform required pre-operational testing. The final permit contains conditions for construction/conversion, injection/operation, PISC, and site closure, but it will not authorize injection if pre-operational testing is needed.

- **Pre-operational testing review/authorization to inject.** The permitting authority reviews the results of the pre-operational testing and any other new information submitted by the Class VI well owner or operator. Information may include an updated AoR model, "as-built" specifications for the injection and monitoring wells, and any revisions to the Project Plans necessitated by the new data.[24] The permitting authority would then approve the updated Project Plans and authorize injection, if appropriate.
- The Class VI well owner or operator will continue to engage the permitting authority throughout the life of the permit (i.e., through site closure) including for activities related to testing, monitoring, and reporting during the injection and PISC phases, as well as during AoR reevaluations, and also for any necessary updates to the project plans, financial responsibility information, or permits, as stipulated in the Class VI regulations and permit conditions.

3.3 Overview of EPA Class VI permitting efforts

As of June 2022, EPA has issued six Class VI permits, all in Illinois. Two of these Class VI permits are currently active, with one in the injection phase and one in the post-injection monitoring phase. The other four Class VI permits were issued for wells that were never constructed. EPA is currently reviewing Class VI permit applications for nine projects, including three in California, one in Indiana, one in Ohio, one in Illinois, and three in Louisiana. Each project may consist of more than one injection well and thus, more than one Class VI permit.

The 2018 passage of revisions and enhancements to the Internal Revenue Code Section 45Q tax credit that provides tax credits for carbon oxide (including CO_2) sequestration led to an increase in Class VI permit applications. EPA has met with more than 100 companies and other interested parties to discuss questions and concerns around GS and the Class VI permitting process. EPA

[24] Any permit modifications not listed as a minor permit modification at 40 CFR 144.41 are considered major modifications and must be issued for public notice before being finalized.

also anticipates that Bipartisan Infrastructure Law investments related to CCUS development and deployment, including funding opportunities (e.g., financial assistance) available through DOE for Carbon Storage Validation and Testing, as well as the DOE CarbonSAFE program will lead to 100 additional Class VI permit applications. The map in Figure 4 presents an overview of potential projects, as of June 2022, in the states where EPA directly implements the Class VI Program. Up-to-date information about Class VI permitting activities is available on EPA's website at: https://www.epa.gov/uic/class-vi-wells-permitted-epa.

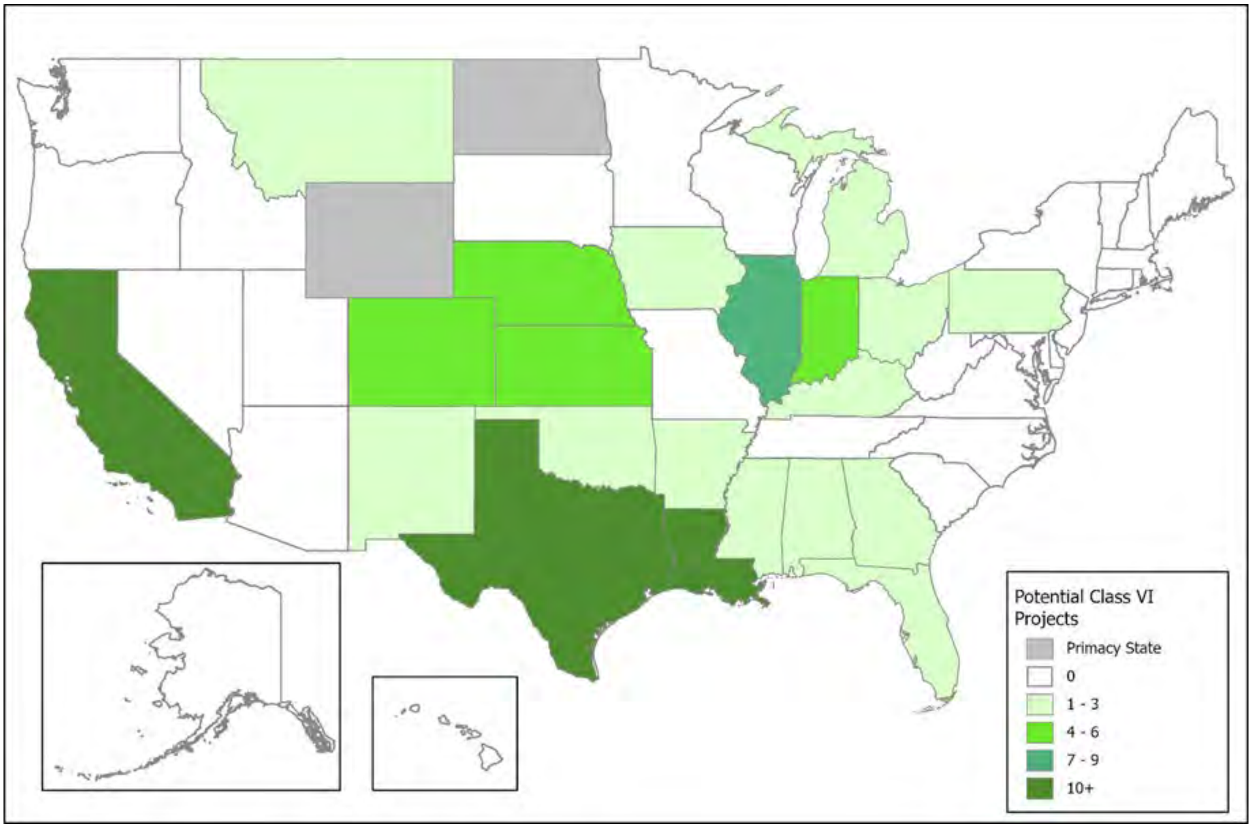

Figure 4. Potential Class VI projects in states where EPA has implementation authority, based on EPA's engagement with entities interested in Class VI permitting.

4. Stakeholder Feedback on Class VI Permitting

Section 4.1 provides an overview of EPA's engagement with stakeholders during which the Agency gathered feedback on the Class VI permitting process. Section 4.2 presents a summary of feedback received.

4.1 Overview of Engagement with Stakeholders

Since the development of the Class VI Rule, EPA has continually engaged with and received feedback from stakeholders representing industry and industry advocates, non-governmental organizations (NGOs), and states (including those with and without Class VI UIC primacy). EPA developed this report considering the input received from various stakeholder groups as well as the recent reports and studies, letters, memoranda, and other communications from these groups.

4.2 Summary of Stakeholder Recommendations

Stakeholders have offered recommendations and suggestions to improve Class VI permitting and protect USDWs. These recommendations are summarized below.

- **Ensure the fair treatment of all people potentially affected by Class VI projects.** Stakeholders recommended that EJ considerations become a routine part of Class VI permitting decisions to ensure meaningful stakeholder engagement in the permitting process and prevent disproportionate community impacts.
- **Implement risk- or performance-based Class VI permitting decisions.** Stakeholders requested additional flexibility to allow the development of site-specific permit conditions. Stakeholders expressed concern that some of the activities required of operators are not needed for every project and advocated for a site-specific, performance-based approach to managing risk to USDWs.
- **Shorten Class VI permitting timeframes.** Citing concerns that long or uncertain permitting timeframes can be an obstacle for CCUS project developers, stakeholders recommended that EPA decrease the timeframe for issuing Class VI permits. Stakeholders recommended that EPA issue a permit to construct within 6 to 12 months of receiving a complete permit application and authorize injection within 3 to 6 months of receiving a well completion report. One recommended avenue for streamlining the review is early coordination with applicants to avoid the need to replicate AoR delineation modeling as part of the permit application review. Stakeholders also suggested that EPA increase staffing and funding to prioritize permit application reviews.
- **Revise the Class VI regulations.** Stakeholders recommended that EPA review the Class VI Rule and data on GS projects to determine if modifications are needed to the Class VI program. They noted that in the Preamble to the final Class VI Rule, EPA stated that the Agency planned to review the rulemaking and relevant data every six years. Stakeholders also offered several specific recommendations to revise the Class VI requirements to align them with a site-specific and performance-based approach and reflect the current understanding of risks associated with Class VI wells.
    - *Eliminate default monitoring timeframe.* The Class VI Rule, at 40 CFR 146.93, requires a default 50 years of monitoring and PISC following the cessation of injection and continued PISC until the Director authorizes closure of the site following a demonstration of non-endangerment to USDWs. This timeframe may be reduced if an operator can demonstrate, either as part of the permit application process or following injection, that a shorter time frame is appropriate. Stakeholders assert that this requirement is overly conservative in many cases (particularly for small demonstration projects) and that it can present a challenge to project financing. They requested that EPA eliminate the 50-year default PISC timeframe and allow applicants to propose a PISC timeframe during the application process or at any time during the operation or closure of the site. They also asked EPA to clarify what is required for authorizing site closure.
    - *Allow AoR to be separated into subareas.* Pursuant to 40 CFR 146.84, Class VI permit applicants must delineate an AoR using computational modeling that

accounts for the physical and chemical properties of all phases of the injected CO_2 stream and displaced fluids. Stakeholders requested that EPA allow the AoR for a Class VI project to be separated into different subareas based on whether the primary concern for USDW endangerment is free-phase CO_2 or pressure-driven upward brine leakage. They assert that the area of the free-phase CO_2 plume around an injection well is typically much smaller than the area of the elevated pressure front capable of endangering a USDW.

- *Allow greater flexibility in selecting methods for tracking and monitoring.* The Class VI regulations require direct monitoring in the injection zone to track the extent of the CO_2 plume and pressure front (at 40 CFR 146.90(g)) and, if needed, surface air monitoring and/or soil gas monitoring to detect movement of CO_2 that could endanger a USDW (at 40 CFR 146.90(h)). Stakeholders asked that the Class VI regulations be revised to allow applicants to use monitoring methods that are appropriate to the site-specific risk to USDWs, including indirect monitoring through perimeter and above-zone monitoring to track the CO_2 plume. They also asked for flexibility when determining the need for surface or soil gas monitoring.
- *Permit pilot, research, and demonstration projects as Class V wells.* 40 CFR 144.15 prohibits the construction of non-experimental Class V wells for GS, and 40 CFR 145.23(f)(4) requires the UIC Program Director to notify operators of Class V experimental technology wells that are no longer being used for experimental purposes that they must apply for a Class VI permit. Stakeholders requested that EPA revise the requirement to allow pilot, research, and demonstration GS projects to be more freely permitted as Class V Experimental Technology (ET) wells.
- *Create aquifer exemptions for Class VI projects.* Under 40 CFR 144.7(a)&(d), aquifer exemptions associated with Class VI wells are not allowed, except for the expansion of an existing aquifer exemption associated with Class II Enhanced Oil Recovery (EOR). Stakeholders asked that EPA allow aquifer exemptions for Class VI projects in all cases.
- *Allow for area permits.* UIC area permits are issued on an area basis rather than for each well individually. Per 40 CFR 144.33, area permits are not allowed for Class VI wells. Stakeholders assert that area permits would streamline the permitting process for very large projects and requested that they be allowed for Class VI projects.
- *Create risk-based financial assurance requirements.* Class VI permit applicants must submit information to demonstrate financial responsibility for corrective action, injection well plugging, PISC and site closure, and emergency and remedial response using allowable financial instruments as described at 40 CFR 146.85. Stakeholders also asked EPA to revise the Class VI financial responsibility requirements in a manner that would reduce the amount of financial coverage that a Class VI well owner or operator would need to carry, focus on a risk-based approach to developing financial responsibility cost estimates, and clarify what information is needed from the applicant.

- **Clarify and codify thresholds for Class II versus Class VI.** Owners or operators that are injecting CO_2 for the primary purpose of long-term storage into an oil or gas reservoir under a Class II permit must obtain a Class VI permit when there is an increased risk to USDWs compared to Class II well operations associated with oil and natural gas production. The factors for determining if there is an increased risk are described in 40 CFR 144.19(b), but stakeholders requested that the process for quantifying "increased risk" be identified in the regulations or guidance. Stakeholders also encouraged EPA to prioritize the expeditious approval of state primacy applications to facilitate the oversight of these transitioning projects. Additionally, stakeholders have requested clarification on the appropriate well classification for the injection of acid gas that contains significant concentrations of CO_2 and was collected as part of oil or natural gas operations. The underground injection of acid gas collected as part of oil or natural gas operations has historically been classified as Class II disposal.
- **Review and revise the Class VI Guidance Documents.** While stakeholders have expressed appreciation for EPA's comprehensive technical and policy guidance documents, they have recommended that EPA review the Class VI guidance documents to ensure that they reflect the latest technical and financial information. They also request that EPA clarify which application components referenced in the guidance documents are required by regulation and which are merely recommended. They encouraged a review to ensure the guidance documents are consistent with the Class VI Rule in full. Stakeholders further suggested that EPA consolidate the number and volume of the documents to make them more user-friendly.

Stakeholders also provided input on topics related to the UIC Program, such as the definition of a USDW. However, these are outside the scope of this report, which focuses on Class VI permitting.

5. EPA Recommendations for Improving Class VI Permitting

EPA has worked with stakeholders to identify potential areas and avenues for improvement. In response to stakeholder feedback (summarized in Section 4), as well as in recognition of the increased interest in Class VI permitting from potential well owners and operators, EPA has identified action items to improve the Class VI permitting process. These items focus on streamlining the permitting process, performing continuous programmatic evaluations, and increasing public outreach, awareness, and transparency while ensuring the protection of public health and the environment by protecting USDWs.

Additional details on the action items and associated tools and strategies to address these categories are provided in Sections 5.1, 5.2, and 5.3, respectively.

5.1 Streamline the Permitting Process

Stakeholders recommended that EPA reduce the amount of time needed to issue final permits for Class VI wells and the time to authorize injection. GS is a complex process that is highly dependent on site-specific conditions; therefore, a robust and comprehensive permit application and permit review process is fundamental to preventing endangerment of USDWs from these activities. EPA agrees that the permitting process could be streamlined, particularly when compared to the process used to permit the very first Class VI wells and has since made significant progress in updating the Class VI permit application and review process to improve the efficiency of permitting timeframes while ensuring the protection of public health and the environment through the protection of USDWs from contamination.

Since the Class VI Rule was finalized in 2010, EPA released comprehensive technical guidance documents to accompany the regulations, discussed in Section 2.1. More recently, EPA has developed a suite of tools and strategies to further streamline the permitting process.

- **Early engagement**. Incomplete or insufficient application materials can result in substantially delayed permitting decisions. When EPA receives incomplete or insufficient permit applications, EPA communicates the deficiencies, waits to receive additional materials from the applicant, and then reviews any new data. This back and forth can result in longer permitting timeframes. EPA therefore encourages applicants to contact their permitting authority early on so applicants can gain a thorough understanding of the Class VI permitting process and the permitting authority's expectations. To assist potential permit applicants, EPA maintains a list of UIC contacts within each EPA Region office on the Agency's website.[25] EPA also focuses on working with the applicants to develop pre-operational testing objectives during the pre-construction phase of a project with the goal of limiting the time that will be needed to authorize injection.
- **GSDT improvements**. EPA has recently upgraded the GSDT and is currently working on additional improvements. The GSDT was designed to create a streamlined Class VI permit application process and guide Class VI permit applicants through the application requirements. In 2020, EPA modified the language in the GSDT reporting modules to enable states with primacy to adopt the system. EPA continues to upgrade the system to improve the efficiency of the application process.
- **GSDT video tutorials**. In June 2021, EPA released five GSDT video tutorials on the Agency's website.[26] These tutorials provide an overview of GSDT capabilities as well as technical instructions for both the permit applicant and permitting authority, such as how to upload supporting documents and how to sign and submit permit application materials and reports within the system.
- **Permit application templates**. The Agency provides multiple templates to support the development of various documents associated with Class VI permitting and project oversight. These templates—for materials to be developed by both owners/operators and permitting authorities—streamline the development and evaluation of applications, issuance of permits and required notifications, and submission of reports.
- **Permit application outline.** In March 2021, EPA released a Class VI Permit Application Outline to guide applicants in the development of a Class VI permit application. The

[25] https://www.epa.gov/uic
[26] https://www.epa.gov/uic/geologic-sequestration-data-tool-gsdt-video-tutorials

WildEarth Guardians

Exhibit 5

State of New Mexico

Class II UIC Program

Peer Review

GROUNDWATER PROTECTION COUNCIL

January 8, 2020

Introduction

In 1974, Congress passed the Safe Drinking Water Act (SDWA), which required the U.S. Environmental Protection Agency (USEPA) to develop minimum federal requirements for underground injection practices. The purpose of the UIC Program is to protect public health by preventing contamination of underground sources of drinking water (USDWs).

The USEPA has defined six classes of injection wells that are permitted and regulated under the SDWA. Class II wells are those that are used to dispose of fluids associated with the production of oil and natural gas.

Under Sections 1422 and 1425, the SDWA provides for delegation of primary enforcement authority (primacy) for the UIC program to states, territories and tribes. As of 2019 the USEPA had delegated primacy for portions of the UIC program to 43 states, territories and tribes.

In September, 2019 the New Mexico Oil Conservation Division (OCD) requested that the Ground Water Protection Council (GWPC) conduct a focused Peer Review of their Class II UIC program. These reviews were reinitiated nearly 4 years ago as part of the State Oil and Gas Regulatory Exchange (a joint project of the GWPC and the Interstate Oil and Gas Compact Commission (IOGCC)). Reviews have been conducted in 5 states since 2015. They involve an evaluation of the effectiveness of a state's Class II UIC program, which demonstrates the ability of the UIC program to protect USDWs and public health. Equal effectiveness with Section 1422 SDWA programs is the standard required of Section 1425 delegated programs. This report details the findings of the peer review team, provides feedback on positive aspects of the program and offers suggestions for enhancing the effectiveness of the Class II UIC program managed by the OCD.

It is important to note that this review is not intended to measure the OCD's UIC program against programs in other states. Implementation of UIC programs vary from state to state due to differences in regional geology and geography, statutory authority, population density and distribution, economics and other factors. These make state to state comparisons of most processes somewhat meaningless from an overall program evaluation standpoint.

During the New Mexico review a team consisting of a former state oil and gas deputy director, former federal UIC regulator and former state oil and gas director studied the current oil and gas and UIC rules of New Mexico and the answers to a standardized questionnaire provided by OCD staff. Following this, the review team conducted an in-state interview of the OCD staff to obtain answers to follow-up questions resulting from the rule and questionnaire review.

Executive Summary

The OCD received SDWA Section 1425 primary enforcement authority (primacy) for the Class II Underground Injection Control (UIC) program from USEPA on March 7, 1982. Their main office is in Santa Fe, with four district offices located in Hobbs, Artesia, Santa Fe and Aztec, which manage all field activities. As of December 4, 2019, the OCD regulated a total of 983 active Class II-Disposal wells and 3249 active Class II- Enhanced Recovery wells. The number of wells regulated is expected to increase significantly in the near future owing to significant increases in exploration and production activity in the Permian Basin. This includes a number of atypical injection well types not routinely seen in other states. These types such as carbon dioxide injection wells, water-gas injection wells, and acid-gas injection wells require additional attention by the OCD.

The recent development of oil and gas production in the Permian Basin has resulted in dramatic increases in UIC related permitting and inspection activities. Applications for permits have increased substantially from an average of 110 per year from 2015 through 2018, to 538 in 2019 (a fivefold increase) (Figure 1).

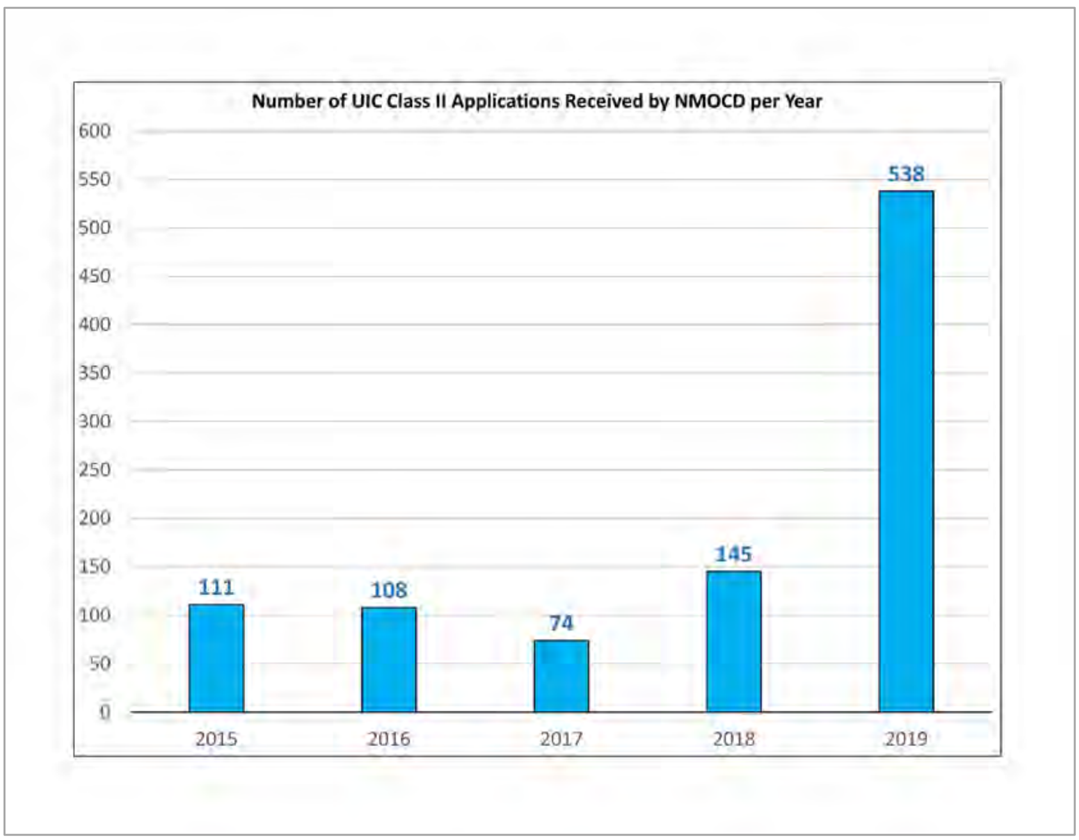

Figure 1: Permit applications by year 2015-2019 Source: New Mexico OCD

As a result, the OCD faces a backlog of over 400 Class II well permit applications pending review. At present workload and staffing levels permit review requires six to nine months. This is much longer than most Class II programs which generally require between 60-90 days to process an application.[1] The OCD projects that its workload will continue to increase in the foreseeable future as a result of Permian production. The large number of proposed new wells in close proximity to each other within the Permian Basin also raise serious potential induced seismicity concerns. Proper assessment of this risk, with its impacts on public health, safety and the environment would require substantial resources, which are not currently available to OCD.

Despite this vastly increased workload, staffing within OCD has not increased as a result of an inability to expand staffing levels, recruit new staff to replace departing staff due to salary constraints, and retain existing staff because of budget limitations. These three conditions have resulted in staffing shortages of between 40-60 percent in some sections and have placed the OCD in a near crisis situation from a programmatic standpoint. At present, the OCD has insufficient staff available to manage critical aspects of a Class II UIC program such as witnessing of Mechanical Integrity Tests (MITs) and casing installation and cementing, conducting periodic file reviews and implementing inspection frequencies at levels that would guarantee protection of Underground Sources of Drinking Water (USDWs). Even if staffing were filled at the current fully authorized levels the program would still be unable to meet all of the needs for USDW protection contemplated in the states' primacy agreement with the U.S. Environmental Protection Agency.

To date the OCD has been unable to increase its budget to provide for elevated staffing levels and has also been unable to reclassify positions to make state service more attractive to those with the qualifications needed to implement a Class II UIC regulatory program. While the OCD is planning a reorganization, which will alleviate some of the current problems faced by the division, this is only a stopgap measure that will not ultimately resolve the issues they face.

Without significant staffing increases, as detailed below, and enactment of staff retention efforts for both field and office positions, the State of New Mexico is likely to face an increasing threat of harm to USDWs and an elevated risk to public health and safety.

The following is a list of the identified strengths of the OCD UIC program and the review teams' critical suggestions for program improvement:

[1] Phone survey of Class II UIC primacy agencies conducted in 2018 by the GWPC

WildEarth Guardians

Exhibit 6

THE 2025 NEW MEXICO SPILL REPORT

Land, Air, & Water Pollution from Oil & Gas

WildEarth GUARDIANS

The 2025 New Mexico Spill Report is written by lead author Melissa Troutman and co-author Rebecca Sobel

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Cover photo: A 2025 spill in the Loco Hills region of southeastern New Mexico. Charlie Barrett / Oilfield Witness
All other photos are credited to WildEarth Guardians unless otherwise noted.

CONTENTS

2025 SPILL DATA SUMMARY

Leaking pipelines are everywhere in the Permian. This pipeline was spewing liquid on the landscape. It appeared as if this pipeline was carrying water used in drilling and fracking. This water is not potable and usually contaminated and only used for drilling and fracking.

38,153 Spills in One Year

- Oil and gas companies reported 38,153 spills in New Mexico in 2025.
- That equals 104 spills every day, on average statewide.

Air Pollution is the Primary Spill Problem

- More than 96% of spills (36,683) were gaseous releases, totaling 9,219,554 thousand cubic feet (MCF) of pollution, mostly methane, a highly potent climate pollutant.
- Gaseous spills occurred every 15 minutes on average.

Volume of Liquid Waste Spills Increase, Damage More Permanent

- Liquid oil and gas spills occurred every six to seven hours on average.
- Operators reported 9.4 million gallons of liquid waste spilled, with over 3.5 million gallons "lost" to the environment.

Public Lands and Waterways are Disproportionately Impacted

- 15 waterways were contaminated by oil and gas spills, 12 waterways were in San Juan County alone.
- The majority of land and water impacts occurred on federal and state public lands.

"Produced Water" is the Most Common Liquid Spill

- Oil and gas production generates at least four barrels of toxic waste known as "produced water" for every barrel of oil.
- This waste contains radioactive materials, heavy metals, carcinogens, and hazardous chemicals, and is the most frequently spilled liquid in New Mexico.

Waste Reuse Facilities Drive Large Spills

- Some of the largest liquid spills occurred at produced water storage and reuse facilities.
- Sites concentrate massive volumes of waste, increasing spill severity when failures occur.

Spills Are Routine, Not Rare

- Gaseous spills are commonly caused by high line pressure, equipment failure, and routine maintenance or normal operations, with liquid spills commonly caused by equipment failure, corrosion, human error and "other."
- Causes indicate spills are predictable outcomes of oil and gas production, not isolated incidents.

Enforcement Lags Behind Pollution

- The same operators repeatedly rank among the top spillers, quarter after quarter.
- Public records show few penalties issued compared to tens of thousands of spills.

INTRODUCTION

What happened in 2025

New Mexico's oil and gas boom has produced record-breaking profits for industry and significant revenue for the state, but it has also produced a growing volume of toxic waste and pollution that current regulatory systems have struggled to manage. Ranking second in oil production and third in natural gas production nationwide, New Mexico experienced tens of thousands of oil and gas spills in 2025, the vast majority of which were releases of air pollutants, primarily methane, making air pollution the most frequent and persistent form of oil and gas pollution statewide.[1]

The liquid material most spilled is oil and gas liquid waste, which industry has euphemistically labeled "produced water." The volume of this waste generated by oil and gas companies in New Mexico has grown so large that disposal capacity is running out. The industry's primary disposal method–injecting waste underground–has been linked to earthquakes and well blowouts as disposal formations become increasingly overpressurized.[2] At the same time, large-scale recycling and storage facilities have become a leading source of major spills. As disposal constraints intensify, oil and gas companies are increasingly pursuing ways to reclassify oil and gas waste as a resource rather than pollution, including proposals to treat and release it into rivers and waterways–setting the stage for major regulatory conflict.[3] These pressures came to a head in 2025 as state regulators were forced to confront whether oil and gas waste should be more tightly regulated—or further commodified—despite rising spill rates and unresolved scientific uncertainty.[4]

Who bears the cost

Despite decades of intensive oil and gas development, New Mexico continues to rank near the bottom nationally on measures of well-being. National data consistently place New Mexico last or near-last in child well-being, poverty, and family economic security, reflecting the failure of extractive development to translate into durable public benefits.[5] Currently, New Mexico has the third highest poverty rate in the nation behind Mississippi and Louisiana, two states that also carry a disproportionate burden of oil and gas development and its associated pollution-related health costs.[6]

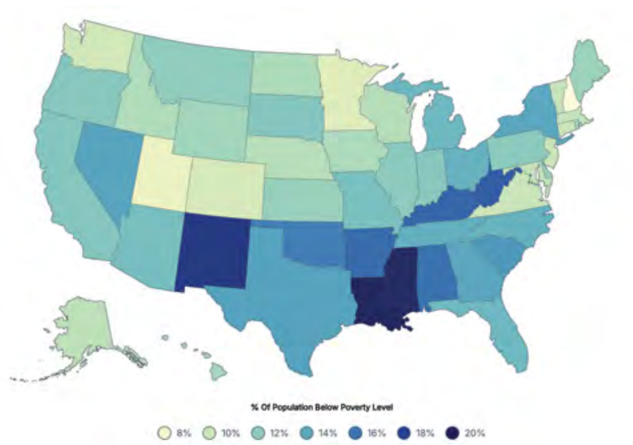
Why the system allows it

While oil and gas production is not the sole driver of poverty, decades of intensive extraction have failed to deliver durable improvements in health, income, or child well-being while imposing disproportionate environmental and public-health burdens. The state's economy remains heavily reliant on extractive industries that externalize environmental and public health costs while shielding operators from accountability, allowing pollution to increase even as social indicators stagnate or worsen.

What must change now

The spill and pollution data presented in this report demonstrate that New Mexico's current regulatory framework permits oil and gas companies to repeatedly pollute land, air, and water while failing to deliver meaningful improvements in quality of life. Without structural reforms to enforcement, transparency, and waste regulation, these dynamics will continue to undermine the health and future of New Mexico's children and communities.

Poverty Rate by State



Source: World Population Review 2026

WHAT'S AT STAKE

New Mexico is home to world-renowned cultural and natural beauty: rare and endangered species, World Heritage sites like Chaco Culture National Historical Park, the world's largest gypsum dunefield (White Sands National Park), cavernous karst geology that includes Carlsbad Caverns National Park, and part of the largest and most diverse desert in North America – the Chihuahuan Desert. New Mexico holds immense wind and solar energy potential, yet it has instead become a central node in the world's highest-producing oil field, the Permian Basin—an industrial footprint increasingly at odds with the state's ecological, cultural, and public health priorities.

Before oil was discovered and drilling companies descended, what has become the "Permian oil patch" was once the largest continuous prairie in North America, full of flora and fauna, especially ground-dwelling birds like the lesser prairie chicken. Oil and gas extraction has transformed the landscape through dense networks of wells, pipelines, tanks, and disposal facilities that routinely result in equipment failure, corrosion, and spills of toxic materials across the state.

New Mexico has long functioned as a national sacrifice zone for extractive and military industries. The state was home to the first nuclear weapons detonation in history at Trinity Site, exposing nearby communities to radioactive fallout later recognized under the federal Downwinders program.[7] New Mexico also bears the legacy of uranium mining on Navajo lands, including the Church Rock uranium mill spill, the largest uranium

spill in U.S. history, which contaminated the Rio Puerco watershed and remains one of the most extensive unfinished uranium cleanups in the country.[8]

Today, the state hosts the nation's only deep geologic repository for transuranic nuclear waste at the Waste Isolation Pilot Plant, where incidents such as the 2014 radiation release have raised ongoing concerns about long-term containment and worker safety.[9] Against this backdrop, widespread oil and gas spill pollution represents not an isolated problem, but another chapter in a long pattern of New Mexico communities bearing disproportionate environmental and health risks for the sake of national energy and security priorities.

POLLUTION FROM OIL & GAS SPILLS

Oil and gas spills can contain known toxic and carcinogenic substances, including per- and polyfluoroalkyl substances (PFAS), radioactive materials such as radium, volatile organic compounds, hazardous air pollutants, gases like methane and hydrogen sulfide, heavy metals including arsenic, and hydrocarbons such as benzene. In addition, spills can include undisclosed "trade secret" chemicals, creating uncertainty about the full range of health and environmental risks wherever spills contact land, water, wildlife, domesticated animals such as cattle, or people. Because oil and gas companies self-report spills, the public record only shows what industry discloses under existing rules. Incomplete spill reports labeled "other," "unknown," or "blank" further obscure the true extent of pollution and prevent meaningful assessment of cumulative environmental and public health harm—harm that has been shown to be widespread and persistent in other oil-producing regions.[10]

Air pollution from oil and gas operations is already the dominant source of statewide emissions in New Mexico. According to the New Mexico Environment Department's most recent greenhouse gas inventory, oil and gas production accounted for roughly half of all statewide greenhouse gas emissions, making it the single largest emissions source, even as production and spill volumes continued to rise.[11]

What Is a "Spill"

Under New Mexico law, an oil and gas "spill" refers to the illegal release, discharge, escape, or disposal of oil, gas, produced water, or other substances associated with oil and gas operations into the environment, including onto land, into surface water or groundwater, or into the air.[12] Spills are reported by operators to the New Mexico Oil Conservation Division (OCD) and entered into the state's spill database as individual releases of specific materials. A single spill event may involve multiple substances, each reported separately.[13]

Oil and gas spills occur in multiple forms, each with their own environmental consequences. Surface spills can contaminate soil, vegetation, surface water, and wildlife habitat. Subsurface spills may migrate underground, contaminate groundwater, or reemerge far from their original source, complicating detection and cleanup. Spills are also categorized by volume contained–or not. "Recovered" spills involve the capture of some portion of the spilled material, while "lost" spills occur when pollutants seep into soil, groundwater, waterways, or the atmosphere. In practice, some spills result in permanent contamination, particularly when gases are released into the air.

What Is Not Accounted For

Even when spills are reported, state spill databases capture only a partial picture of pollution from oil and gas operations. Spill reporting and cleanup requirements in New Mexico are governed by rules adopted by the New Mexico Oil Conservation Commission (OCC) and implemented by the Oil Conservation Division (OCD), which require reporting of certain listed materials but do not mandate comprehensive disclosure or routine testing for many contaminants used or released during drilling, hydraulic fracturing, or waste management.

As a result, spill records generally exclude hazardous air pollutants released during venting, flaring, and equipment failures, including volatile organic compounds (VOCs) and other hazardous air pollutants (HAPs) linked to respiratory, cardiovascular, neurological, and developmental health harms, particularly for communities living near production, distribution, and waste infrastructure.[14] Reporting also fails to capture radioactive constituents and many trade secret chemicals, including per- and polyfluoroalkyl substances (PFAS).

These omissions have consequences. The U.S. Environmental Protection Agency and the National Academies of Sciences report that most chemicals used in oil and gas extraction lack adequate public toxicity data.[15] This is particularly true for chronic exposures, chemical mixtures, and proprietary substances, making comprehensive health risk assessment impossible for the majority of chemicals in use.[16] **The public record therefore does not reveal the full toxicity or scale of pollution released during spill events.** This obscures risks to workers, first responders, nearby communities, and ecosystems and limits regulators' and the public's ability to assess cumulative and long-term impacts.

These data gaps are compounded by the oil and gas industry's long-standing exemption from key federal hazardous-waste and environmental laws, including the Resource Conservation and Recovery Act (RCRA), Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), and the Safe Drinking Water Act (SDWA).[17] Under these exemptions, substances that would otherwise trigger hazardous-waste handling, testing, cleanup, and disclosure requirements are regulated under a less protective framework.

Research also documents the widespread use of PFAS in oil and gas operations. PFAS are highly persistent "forever chemicals" linked to cancer, immune suppression, endocrine disruption, and developmental harm, yet they are not required to be tested for or identified in spill reports.[18] PFAS use in oil and gas operations can also be kept hidden from the public under trade-secret claims.[19] As a result, PFAS contamination from oil and gas spills may go undetected, even as these chemicals accumulate in soil, water, wildlife, and human bodies.

Within these limitations, the state's spill database identifies only a defined subset of materials that operators are required to report when a spill occurs. Those reported materials are summarized below.

MATERIALS REPORTED IN OIL AND GAS SPILLS

Produced water

Toxic liquid waste generated during oil and gas extraction that returns to the surface after drilling and hydraulic fracturing. Produced water can contain salts, heavy metals, radioactive materials (including radium), hydrocarbons, chemical additives, and undisclosed trade secret chemicals, including PFAS. It is the largest waste stream in oil and gas production. It is also the most spilled liquid material.

Crude oil

A naturally occurring mixture of hydrocarbons extracted from underground geological formations. Crude oil and petroleum liquids contain hazardous constituents including BTEX compounds (benzene, toluene, ethylbenzene, and xylenes) and sulfur-containing compounds and trace metals; when spilled, these substances can contaminate soil and water and create inhalation and fire risks.

Chemicals used in drilling, fracking, and maintenance

Chemical substances used to drill wells, hydraulically fracture formations, control corrosion, inhibit scale, and maintain equipment. These chemicals include biocides, surfactants, friction reducers, acids, solvents, and corrosion inhibitors, many of which are hazardous and may be withheld from public disclosure.

Condensate

A liquid hydrocarbon recovered from natural gas production when pressure and temperature decrease at the surface. Condensate is highly volatile and flammable and may contain benzene and other hazardous air pollutants.

Fuels (diesel and gasoline)

Refined petroleum products used to power drilling rigs, generators, vehicles, and other oil and gas equipment. Fuel spills pose risks of soil contamination, groundwater pollution, and fire or explosion hazards.

Glycol

A chemical compound, commonly ethylene glycol or triethylene glycol, used in oil and gas operations for dehydration and freeze protection. Glycols are toxic if ingested, can contaminate soil and water, and cause harm to wildlife and humans.

Natural gas liquids (NGLs)

Hydrocarbon liquids separated from natural gas during processing, including ethane, propane, butane, and pentanes. NGLs are highly flammable and pose explosion and air quality risks when released.

Natural gas (methane)

A colorless, odorless gas composed primarily of methane, the main component of natural gas. Methane is a potent climate pollutant and contributes to ozone formation when released into the atmosphere. Methane spills are typically unrecoverable once released.

Hydrogen sulfide

A colorless gas with a characteristic “rotten egg” odor that occurs naturally in some oil and gas formations. Hydrogen sulfide is highly toxic, can cause respiratory failure or death at high concentrations, and poses immediate risks to workers and nearby communities during releases.

Carbon dioxide (CO_2)

A colorless, odorless gas released during oil and gas production, processing, and waste handling, including venting, flaring, and equipment failures. While not toxic at ambient concentrations, carbon dioxide is a greenhouse gas that contributes to climate change and poses asphyxiation risks in confined or high-concentration release scenarios.

“Unknown” or “other”

A spill category used in state reporting systems when the operator does not identify the specific material released. “Unknown” and “other” designations prevent reviewers from fully assessing toxicity, exposure pathways, or appropriate cleanup requirements.

“Blank”

A spill record field left empty by the reporting operator, indicating missing or undisclosed information about the material released. “Blank” entries function similarly to “unknown” designations, undermining transparency and cumulative impact analysis.

2025 KEY FINDINGS

THESE FINDINGS SHOW OIL AND GAS SPILLS IN NEW MEXICO ARE PREDICTABLE, PERSISTENT, AND CONCENTRATED AMONG REPEAT OPERATORS.

Spills Across Time (2022-2025)

While the overall number of reported oil and gas spills has generally decreased between 2022 and 2025, ***the volume of toxic waste spilled increased dramatically in 2025.*** Liquid spill volumes rose by 93% compared to 2024, 84% compared to 2023, and 51% compared to 2022.

The volume of liquid waste permanently lost to the environment increased by as much as 87% year over year, showing that spills are becoming fewer in number but significantly larger in scale and impact.

Fewer spills does not equal less pollution. 2025 had fewer spill events, but more volume spilled than any other year.

	2022	2023	2024	2025
ALL SPILLS	42,725	54,618	42,208	38,153
LIQUID SPILLS	1,780	1,593	1,393	1,470
LIQUID VOLUME SPILLED	6,262,830 *gal*	5,120,052 *gal*	4,892,832 *gal*	9,442,230 *gal*
LIQUID VOLUME LOST	2,590,980 *gal*	1,879,374 *gal*	2,017,554 *gal*	3,515,064 *gal*
GASEOUS SPILLS	40,945	53,025	40,815	36,683
GASEOUS VOLUME SPILLED	16,013,546 *MCF*	20,020,455 *MCF*	11,471,954 *MCF*	9,219,554 *MCF*
GASEOUS VOLUME LOST	16,013,546 *MCF*	20,020,455 *MCF*	11,471,954 *MCF*	9,219,554 *MCF*

The table above shows the number and volumes of gaseous, liquid, and total spills for the years 2022 - 2025.

Bad Actors, Bad Neighbors

Between 2022 and 2025, the same seven oil and gas companies consistently ranked among the top spillers, reflecting the concentration of pollution among the state's largest producers.[20] EOG Resources reported more spilled than any other operator, ranking first each year and accounting for 34,767 spills in only four years. EOG is also the largest oil and gas producer in NM.

Spill frequency is highest among the largest oil and gas producers, indicating a clear relationship between production volume and pollution.

TOP SPILLERS ACROSS TIME, 2022-25	TOTAL SPILLS
EOG Resources	34,767
XTO Energy / XTO Permian Operating	15,338
Matador Production	11,812
Earthstone Operating	9,249
Devon Energy Production	9,008
COG Operating / COG Production	5,271
Mewbourne Oil	3,779

The table above shows total spills for seven companies that were among the top spillers every year from 2022 - 2025.

2025 BIGGEST SPILLS BY QUARTER

Q1 / LIQUID

DKL ENERGY COTTONWOOD

Date	**03/11/25**
Landowner	**Federal**
County	**Lea**
Cause	**Corrosion**
Material	**Produced water**
Volume	**169,092 gal spilled / lost**

A corroded pipeline operated by DKL Energy spilled 4,026 barrels (169,092 gallons) of toxic oil and gas waste into the surrounding landscape. The spill was discovered in May 2025 and still being remediated in September.

Q1 / AIR

DCP OPERATING

DCP Operating had to “blowdown” a section of pipeline, venting 18,647 mcf of natural gas, when a 4” poly gathering line “failed”. According to the report DCP filed with the state, the natural gas release was over 93% methane, a climate super pollutant.

Date	**02/7/25**
Landowner	**Federal**
County	**Eddy**
Cause	**Blow out**
Material	**Natural gas vented**
Volume	**18,647 mcf spilled / lost**

Q2 / LIQUID

EOG RESOURCES

Date	**06/10/25**
Landowner	**State**
County	**Lea**
Cause	**Overflow**
Material	**Produced water**
Volume	**158,424 gal spilled / 143,094 gal lost**

A June 10th spill at an EOG Resources produced water reuse pit resulted in contamination of state public lands. In the photo, sourced from state files, the path of pollution can be seen as brown stains on land and vegetation.

Q2 / AIR

XTO ENERGY

Between 2022-2025, XTO Energy reported that it released 889,494 mcf during other venting and flaring events at this single facility (XTO PERMIAN MIDSTREAM NGGS; ID # fAPP2218240516). While these other releases are not all considered "spills" by the state, they represent a pattern of reportable, routine gaseous pollution that impacts air quality in the Permian region, where air quality is already unhealthy due to oil and gas activity.

Date	**06/8/25**
Landowner	**(blank)**
County	**Eddy**
Cause	**Repair & maintenance**
Material	**Natural gas flared**
Volume	**16,627 mcf spilled / lost**

2025 BIGGEST SPILLS BY QUARTER

Q3 / LIQUID

OXY USA

Date	**07/15/25**
Landowner	**Federal**
County	**Lea**
Cause	**Equipment failure**
Material	**Produced water & crude oil**
Volume	**Produced water: 1,608,810 gal spilled / 1,543,374 gal lost** **Crude oil: 126,546 gal spilled / 121,422 gal lost**

The biggest spill of 2025 occurred on federal public land in Lea County when the wall of a produced water recycling pit collapsed, polluting the surrounding landscape with 36,747 barrels (1,543,374 gallons) of toxic oil and gas waste and 2,891 barrels (121,422 gallons) of crude oil. This facility was equipped with a leak detection system and constructed to prevent "overtopping" according to a remediation plan submitted to the state.

Q3 / AIR

COG OPERATING

COG Operating reported the largest gaseous spill in Q3 2025, which it blamed on another company's failure to notify COG of production changes in a connected operation. In the oilfields, multiple companies can feed into the same natural gas pipelines. When there is too much pressure in the line, it has to be opened and vented or flared to avoid explosions and other problems.

Date	**09/5/25**
Landowner	**(blank)**
County	**Eddy**
Cause	**High line pressure**
Material	**Natural gas flared**
Volume	**18,112 mcf spilled / lost**

Q4 / LIQUID

XTO ENERGY

Date	**10/31/25**
Landowner	**Federal**
County	**Eddy**
Cause	**Human error**
Material	**Produced water**
Volume	**130,284 gal spilled / 126,084 gal lost**

XTO reported a major spill of toxic oil and gas waste from a pipeline caused by “third party” operations nearby. According to state records, soil sampling and remediation efforts were ongoing as of January 15, 2026.

Q4 / AIR

CIVITAS PERMIAN OPERATING

COMPONENTS	MOL. %
Nitrogen	0.586
Carbon Dioxide	0.207
Methane	77.896
Ethane	11.118
Propane	4.867
Iso-butane	0.880
n-Butane	1.883
Iso-pentane	0.551
n-Pentane	0.617
Hexanes Plus	1.445
	100.00

Date	**12/17/25**
Landowner	**(blank)**
County	**Eddy**
Cause	**Normal operations**
Material	**Natural gas vented**
Volume	**18,301 mcf spilled / lost**

Civitas reported the largest gaseous spill of Q4 2025, which the company attributed to “normal operations,” writing in state records that there was “no way to avoid” the release due to “maintenance/repairs to address unforeseen issues.” Like most gaseous spills, the major component reported was methane, which is 80x more potent a greenhouse gas than carbon dioxide in the near term.

2025 TOTAL SPILLS

Oil and gas companies reported **38,153 spills in New Mexico in 2025 - an average of 104 spills per day** - reflecting an immense amount of pollution to air, land, and water.[21]

Gaseous spills overwhelmingly dominated spill activity in 2025, accounting for 96% of all reported spills, averaging **one gaseous spill every 14-15 minutes,** and releasing more than **9.2 million thousand cubic feet (MCF)** of methane and other gases, none of which was recovered once released.[22]

The methane spilled into New Mexico's air in 2025 caused climate damage comparable to **putting more than a million additional cars on the road** for an entire year—without moving a single person or producing any public benefit.[23]

Liquid spills, occurring on average every six to seven hours, resulted in **9,446,051 gallons of liquid waste released in 2025,** consisting mostly of crude oil and toxic waste known as "produced water."[24]

3.5 million gallons of waste were "lost" to the environment through seepage into the ground or groundwater, runoff into water-ways, and contamination of soil, flora, and fauna.

The volume of waste spilled would fill about **1,900 tanker trucks,** with roughly 700 tanker trucks' worth of unrecoverable waste released into soil and water.[25] The volume of toxic waste spilled would fill a convoy stretching **over 20 miles**, roughly the north-south length of the greater Albuquerque urbanized area.[26]

On average, companies spilled 104 times per day in 2025; gas spills occur every 15 minutes, liquid spills every 7 hours.

2025	All Spills	Gaseous Spills	Gaseous Spill Volume (MCF)	Liquid Spills	Liquid Volume Spilled (GAL)	Liquid Volume Lost (GAL)
Q1	10,578	10,237	2,752,067	341	3,294,174	490,562
Q2	10,250	9,888	2,609,056	362	1,547,028	425,922
Q3	9,515	9,094	2,089,964	421	3,188,485	2,061,047
Q4	7,810	7,464	1,768,457	346	1,416,364	538,349
TOTAL	38,153	36,683	9,219,544	1,470	9,446,051	3,515,880

The table above shows the number of times a gaseous or liquid spill was released into the environment on a quarterly basis.

MOST COMMON POLLUTANTS

The most frequently reported materials spilled in 2025 were natural gas (methane), and produced water. Methane is a potent climate pollutant, over 80 times more potent than carbon dioxide over a 20-year time-frame.[27] For every barrel of oil produced, oil and gas companies generate an average of four barrels of produced water, a toxic waste stream known to contain radioactive materials, heavy metals, volatile organic compounds, and undisclosed chemicals.[28] Despite its toxicity, produced water spills remain poorly characterized, and research has shown that 86% of chemicals found in produced water lack sufficient toxicity data to complete a risk assessment, underscoring the significant uncertainty about health and environmental impacts.[29]

The most common spill materials are also among the most dangerous to communities and ecosystems.

POLLUTANT	# OF SPILLS
Natural Gas Flared	34,978
Produced Water	925
Other	833
Natural Gas Vented	739
Crude Oil	391
Carbon Dioxide	150
Condensate	102
Chemical	7
Drilling Fluid	6
Lube Oil	5
Unknown	5
Motor Oil	4
Gasoline	2
Hydrogen Sulfide	2
Diesel	1
Glycol	1
Natural Gas Liquids	1
Sulfuric Acid	1

The table above shows the number of times a particular spill material was reported in 2025.

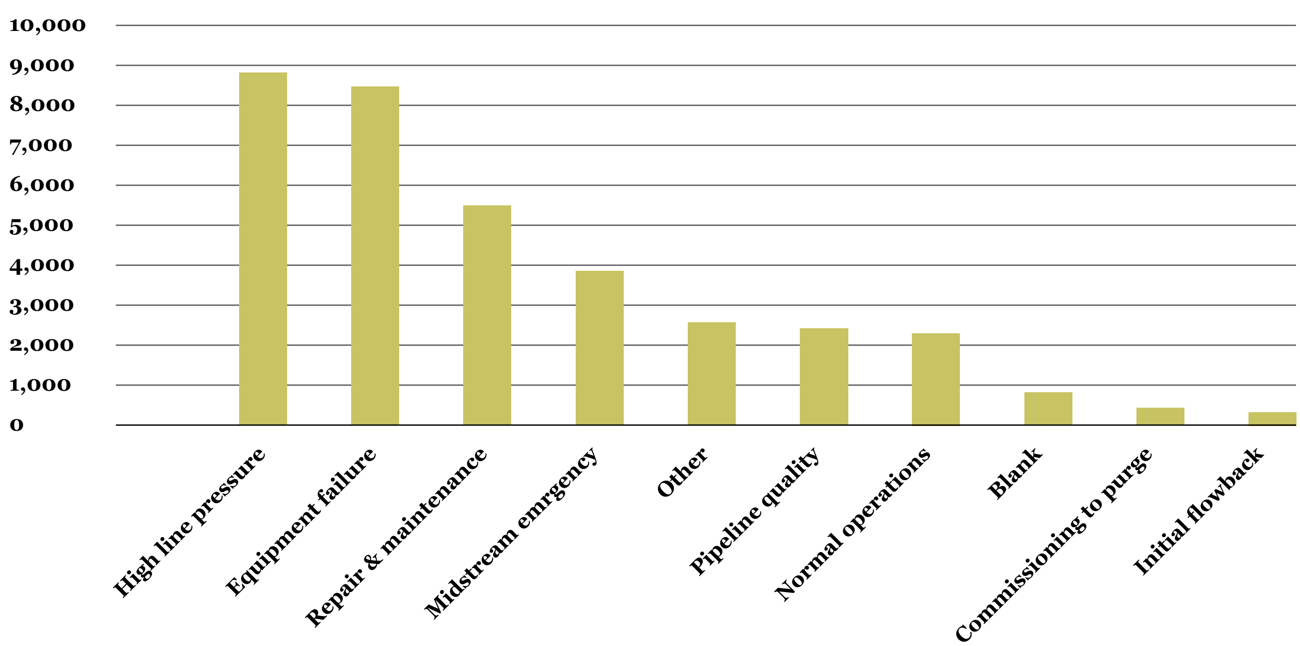
MOST COMMON CAUSES OF GASEOUS SPILLS

The most common causes of gaseous spills causing air pollution were attributed to high line pressure, equipment failure, and repair and maintenance activities.

CAUSE	GASEOUS SPILLS
High line pressure	8,815
Equipment failure	8,509
Repair and maintenance	5,639
Midstream emergency maintenance	3,922
Other	2,599
Pipeline quality specifications	2,446
Normal operations	2,351
Blanks	803
Commissioning to purge	461
Initial flowback	302

The table above shows the self-reported cause of spill and the number of spills associated with that cause.

2025 TOP GASEOUS SPILL CAUSES



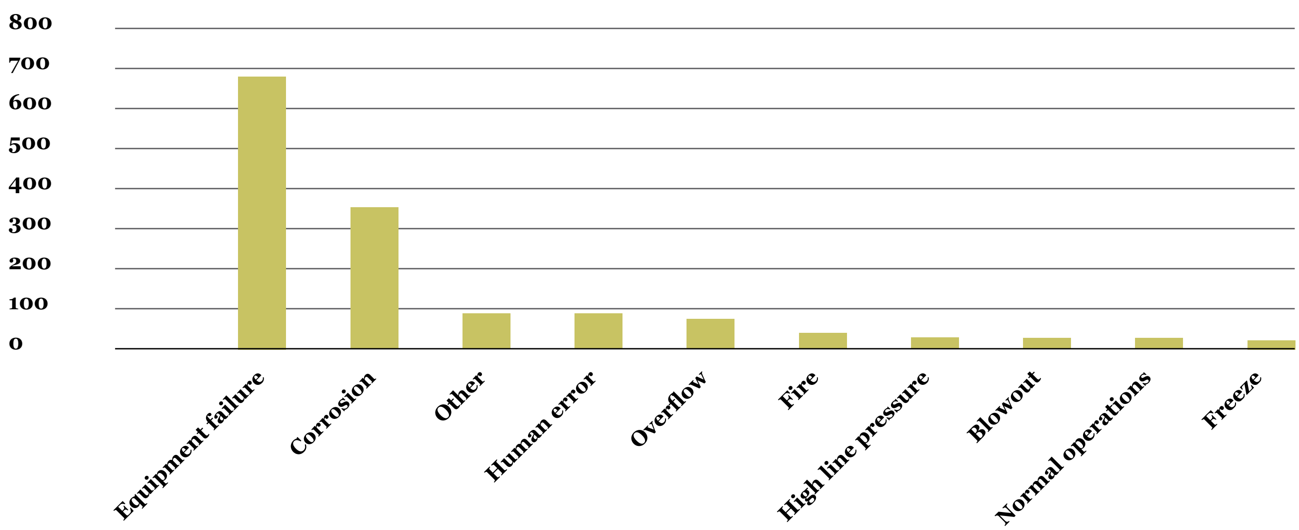
MOST COMMON CAUSES OF LIQUID SPILLS

The most common causes of liquid spills causing land and water pollution were attributed to equipment failure, corrosion, human error and "other."

CAUSE	LIQUID SPILLS
Equipment failure	679
Corrosion	363
Other	85
Human error	85
Overflow	69
Fire	39
High line pressure	29
Blowout	26
Normal operations	25
Freeze	18

The table above shows the self-reported cause of spill and the number of spills associated with that cause.

2025 TOP LIQUID SPILL CAUSES



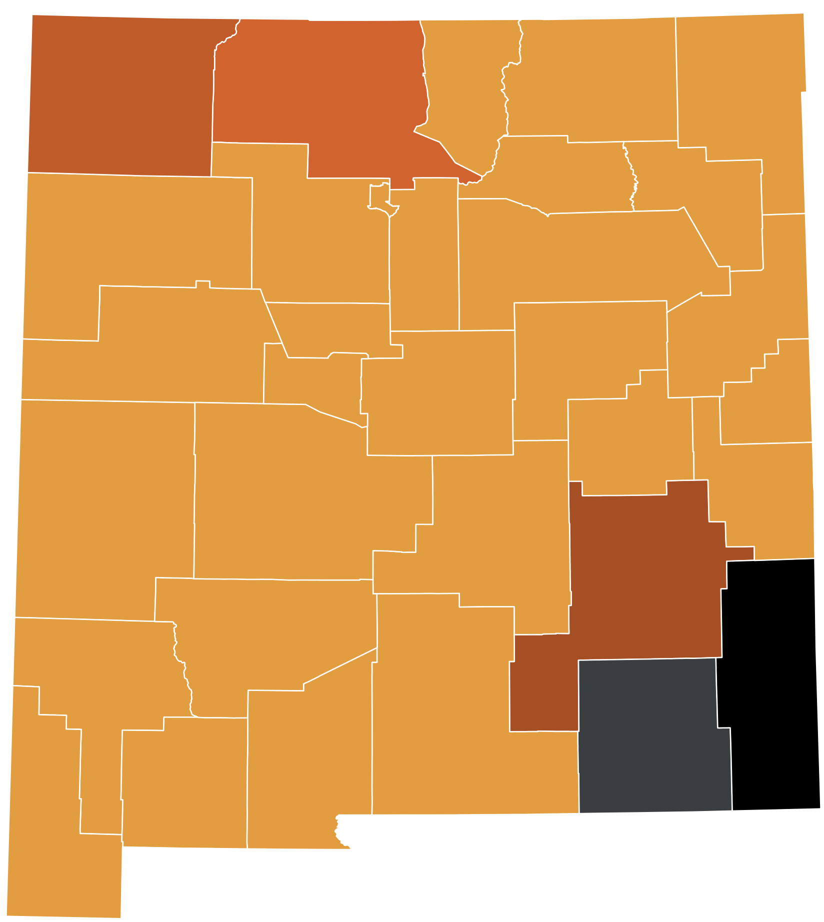
MOST POLLUTED COUNTIES

Oil and gas spills were heavily concentrated in southeastern New Mexico, with Lea and Eddy counties accounting for the vast majority of reported spills. Together, these two counties experienced over 37,000 spills in 2025. Spills were also reported in counties far from the Permian Basin, including San Juan and Rio Arriba Counties, demonstrating that spill risks extend beyond a single region. Spills were also reported in Roosevelt County (9), Sandoval County (6), Harding County (2), Union County (1), Otero County (1), and Torrance County (1).

Spill pollution closely tracks oil and gas development intensity. Communities in the Permian Basin bear the greatest burden, but other regions are not immune.

COUNTY	# OF TOTAL SPILLS
• Lea	22,137
• Eddy	15,301
• Chaves	365
• San Juan	219
• Rio Arriba	110

The table above shows the number of total spills that occurred within each county.



MOST IMPACTED LANDOWNERS

For all 1,470 liquid spills in 2025, state data identifies the affected landowner. In contrast, of the 36,683 gaseous spills, land ownership was left blank for 36,282 events (98%). As a result, it is not possible to determine which landowners or communities were most impacted by air pollution releases, including methane and other hazardous gases. Among liquid spills where land ownership was identified, federal public lands were the most impacted, followed by state trust lands, highlighting the disproportionate burden placed on public resources held in trust for New Mexicans.

Data gaps prevent transparency related to air pollution impacts, while liquid spill data show that public lands bear the greatest documented harm.

LEASEHOLDER	LIQUID SPILLS	GASEOUS SPILLS
Federal	**828**	**57**
State	**323**	**36**
Private	**309**	**302**
Navajo	**5**	**6**
Indian	**3**	**0**
Jicarilla	**1**	**0**
“Blank”	**0**	**36,282**

The table above shows the number of liquid and gaseous spills for 2025 by land ownership.

WATER CONTAMINATION

In 2025, 15 waterways were contaminated by oil and gas spills, with 12 of these incidents occurring in San Juan County. Pipeline corrosion and equipment failure were responsible for the majority of water contamination events. A small number of operators accounted for multiple waterway impacts, with Harvest Four Corners, LLC responsible for six contaminated waterways, all in San Juan County.

Repeat offenders are responsible for spills impacting waterways, posing significant risks to water quality, mostly in the San Juan Basin.

OPERATOR	WATERWAYS AFFECTED	COUNTY
Harvest Four Corners	**6**	**San Juan**
Hilcorp Energy Company	**2**	**San Juan**
Dugan Production	**2**	**San Juan**
Enduring Resources	**1**	**San Juan**
DJR Operating	**1**	**San Juan**
Enterprise Field Services	**1**	**San Juan**
Solaris Water Midstream	**1**	**Eddy**
Targa Northern Delaware	**1**	**Lea**

The table above shows the number of spills affecting waterways per county in 2025.[30]

2025 TOP POLLUTERS

The following companies reported the most spills, sorted here into three categories – total spills, gaseous spills of air pollutants, and liquid spills of land and water pollutants.[31] A relatively small number of operators accounted for a disproportionate share of reported spills in 2025. The same companies appear repeatedly quarter after quarter, indicating a chronic pattern of pollution. Companies such as EOG Resources, Devon Energy, Matador Production, XTO/ExxonMobil, Civitas Permian, and Occidental (OXY) ranked among the top polluters across multiple categories, underscoring the role of large, high-producing operators in driving spill totals.

Spill pollution is concentrated among repeat operators, demonstrating that existing enforcement mechanisms have failed to meaningfully change behavior among chronic polluters.

AIR POLLUTANTS

1	**EOG Resources**	**(8,255)**
2	**Matador Production**	**(4,546)**
3	**XTO/ExxonMobil**	**(3,769)**
4	**Civitas Permian**	**(2,200)**
5	**Permian Resources**	**(2,150)**
6	**Longfellow Energy**	**(1,456)**
7	**Avant Operating**	**(1,301)**
8	**OXY / Occidental**	**(1,285)**
9	**COG**	**(1,132)**
10	**Raybaw Operating**	**(1,129)**

LAND / WATER POLLUTANTS

1	**Devon Energy**	**(276)**
2	**XTO/ExxonMobil**	**(162)**
3	**COG**	**(97)**
4	**OXY / Occidental**	**(75)**
5	**EOG**	**(47)**
6	**Permian Resources**	**(38)**
7	**Matador Production**	**(35)**
8	**Cotera Energy**	**(26)**
9	**Mewbourne Oil**	**(23)**
10	**Avant Operating**	**(17)**

The tables above shows the number of spills, gaseous and liquid the top 10 operators released in 2025.[32]

ACCOUNTABILITY & ENFORCEMENT

On February 25, 2020, New Mexico's Oil Conservation Division (OCD) regained authority to assess civil penalties for violations of the Oil and Gas Act following updates to its enforcement rules. Under these rules, OCD may assess penalties of up to $2,500 per day per violation, and up to $10,000 per day when a violation presents a risk to public health or safety, causes significant environmental harm, or continues beyond the time specified in a notice of violation or stipulated order. Total civil penalties are capped at $200,000 per violation.[33]

On August 24, 2021, the New Mexico Oil Conservation Commission adopted a rule that explicitly prohibited liquid oil and gas spills, including releases of oil, chemicals, and produced water.[34] This regulatory update followed a petition filed by WildEarth Guardians and the Oil Conservation Division and was intended to strengthen spill prevention and cleanup authority. At the time, the Energy, Minerals and Natural Resources Department (EMNRD) described the rule change as providing OCD with additional tools to prevent and remediate spills in the oil and gas field.[35]

Together, these actions restored and expanded the state's legal authority to penalize spill-related violations and require cleanup. Yet publicly available records show that enforcement has not been applied at a scale commensurate with the volume and frequency of reported spills. From 2021 to 2025, only a small number of civil penalties were issued by the New Mexico Oil Conservation Division, despite tens of thousands of reported spills and clear evidence that the same operators repeatedly rank among the top polluters quarter after quarter.[36]

The gap between legal authority and enforcement outcomes indicates a systemic failure to use existing tools to deter repeat pollution.

Absent consistent enforcement, the spill problem is likely to intensify as wells age and production declines. When revenues fall below cleanup costs, operators often delay or abandon plugging and remediation obligations, increasing the risk of leaks from deteriorating wells, pipelines, and tanks. New Mexico already faces an estimated $200 - $400 million in plugging and remediation liabilities from abandoned wells—costs that are increasingly shifted from polluters to taxpayers.[37]

Spill Response and Cleanup

While liquid oil and gas spills are explicitly prohibited under state law, gaseous releases are often reported as "spills" or "releases" without clear legal consequences, despite their frequency, climate impact, and public health risks. New Mexico law requires oil and gas operators to promptly control, contain, and remediate spills and to clean up contaminated soil and water resulting from oil and gas operations.[38] In practice, however, not all spills can be fully remediated, and many require years of monitoring and corrective action. In cases involving groundwater contamination, subsurface releases, or unknown spill sources, contaminants may persist indefinitely in the environment.

State regulations specify cleanup requirements and the substances that must be addressed when contamination occurs. Soil cleanup standards for oil and gas releases require removal or treatment of contaminated soil to protective levels based on the type and extent of contamination.[39] Water contamination standards are governed by New Mexico water quality criteria adopted and enforced by the Water Quality Control Commission (WQCC), including standards designed to protect surface water, groundwater, and designated uses such as drinking water, agriculture, and aquatic life.[40]

Despite these requirements, cleanup obligations are not absolute. When an operator asserts that meeting cleanup standards is "technically infeasible" or would impose an "unreasonable burden," the company may petition the OCD for an alternative abatement standard. If approved, this allows reduced cleanup requirements and permits some contamination to remain in place, subject to conditions set by the Division.[41]

These provisions create a regulatory pathway for pollution to persist in the environment, particularly where contamination is difficult to locate, expensive to remediate, or challenging to verify. Over time, the cumulative effect of incomplete cleanup, undocumented contaminants, and repeated spills compounds risks to land, water, air quality, and public health, while shifting long-term burdens away from polluters and onto taxpayers and communities.

HOW TO STOP SPILL POLLUTION

1. Enforce civil penalties consistently and transparently

The Oil Conservation Division should assess civil penalties for recurring spill violations, with penalty amounts reflecting the severity, duration, and environmental harm of each incident. Enforcement outcomes should be publicly reported and linked to specific spill events, allowing the public to evaluate deterrence and compliance.

2. Require mandatory penalties for illegal liquid spills

Liquid oil and gas spills have been illegal in New Mexico since 2021. Penalties for these violations should be mandatory, not discretionary, particularly where spills involve produced water, crude oil, or chemicals that contaminate land or water.

3. Impose permit consequences for chronic polluters

Operators with repeated spill violations should face permit suspensions, denials of permit renewals, or increased bonding requirements. Allowing chronic violators to continue expanding operations without consequence undermines spill prevention and rewards noncompliance.

4. Require full chemical disclosure and end trade secret exemptions

All chemicals used or released during oil and gas operations must be fully disclosed to regulators, emergency responders, and the public to enable meaningful risk assessment and spill response. Trade secret claims should not shield hazardous substances from disclosure or accountability when public health and environmental safety are at stake.

5. Ban PFAS in all oil and gas operations to protect public health

PFAS and other “forever chemicals” used in oil and gas operations pose serious health risks, including cancer, immune system damage, and developmental harm, and persist in the environment long after release. New Mexico should prohibit the use of PFAS in oil and gas drilling, fracking, and waste handling to prevent irreversible contamination of land, water, and communities.

6. Close loopholes that inhibit full cleanup

The use of alternative abatement standards should be strictly limited. Cleanup standards must prioritize complete remediation, not long-term contamination management framed as technical infeasibility. Removing the hazardous waste exemption for oil and gas materials will increase remediation standards and clean up oversight.

7. Strengthen spill prevention and reporting rules

OCD should update rules to require greater spill prevention measures, such as improved monitoring for most common spill causes, and accessible reporting of all spill information to the public. Data gaps, including the “unknown” or “blank” categories in the spill data, make it impossible to assess risk for specific demographics.

8. Accelerate cleanup of inactive and orphaned wells

Legacy infrastructure remains a major source of spills and leaks. The state should expedite plugging and remediation of inactive and orphaned wells and update rules to require operators to post sufficient financial assurance to prevent future abandonment.

9. Prevent reuse of oil and gas waste off the oilfield

New Mexico should prohibit the reuse of treated or untreated “produced water” outside of oil and gas activities. Moving this waste off the oilfield would create additional pathways for spills, leaks, contamination, and other accidents to occur.

10. Pause new permitting until spill pollution declines

The state should pause approval of new drilling permits until spill pollution demonstrably declines and enforcement capacity matches the scale of oil and gas activity. Expansion without accountability will only compound existing harm.

CONCLUSION

The data presented in this report show that oil and gas spill pollution in New Mexico is routine, persistent, and largely unpenalized. In 2025 alone, operators reported more than 38,000 spill events, the vast majority involving uncontrolled releases of gas to the atmosphere, alongside hundreds of liquid spills contaminating land and water. These releases are not isolated accidents, but predictable outcomes of an extraction system that generates enormous volumes of waste and relies on aging infrastructure, high-pressure operations, and insufficient oversight.

While New Mexico has taken important steps to strengthen spill rules and restore enforcement authority, the scale and persistence of spill pollution reveal that existing tools are not being used effectively. The same operators are repeatedly the top spillers, yet public records do not show corresponding consequences sufficient to deter future violations. Data gaps and undisclosed chemicals further obscure the true extent of harm and long-term risks to communities, public lands, and taxpayers. The state has clear authority to enforce penalties, require full chemical disclosure, deny permits to chronic violators, and prevent the discharge of toxic oil and gas waste. **What is lacking is not legal authority, but the political and regulatory will to apply it at the scale this crisis demands.**

Protecting New Mexico's land, water, air, and communities requires treating spill pollution as the public health and environmental emergency it is. Until enforcement becomes routine, and transparency replaces secrecy, pollution from oil and gas spills will continue to compound year after year. The findings in this report make clear that meaningful accountability is both possible and urgently needed. The choice facing New Mexico is not whether spills will occur, but whether the state will continue to allow them without consequence.

Absent decisive enforcement and transparency, spill pollution will remain a predictable outcome of New Mexico's oil and gas industry rather than a preventable failure.

METHODOLOGY

This report is based on analysis of publicly available oil and gas spill data reported to the New Mexico Oil Conservation Division (OCD) for calendar year 2025. Primary data sources include the OCD's Incident Search and Spill Search databases, which together provide incident-level and material-level spill records, as well as quarterly OCD spill records for Q1–Q4 2025.[42] These data were supplemented with WildEarth Guardians' quarterly Oil & Gas Waste Watch reports and associated analyses, which track spill trends and patterns over time. All records were compiled into a consolidated spreadsheet capturing reported spill materials, volumes, causes, operators, counties, and land ownership fields to enable annual aggregation and cross-comparison across data sources.[43]

This analysis reflects several inherent limitations in the available spill data and regulatory reporting systems. Spill records are self-reported by oil and gas operators, and independent verification of reported information is limited. Some records lack complete data on material type, spill volume, cause, or affected land ownership, constraining the ability to fully quantify impacts or assign responsibility in every case.

Reported gaseous spill volumes reflect only documented releases and do not capture the full suite of associated air pollutants, including volatile organic compounds and other hazardous air pollutants that may be released concurrently. In addition, enforcement actions and civil penalties are not systematically linked to individual spill records in publicly available databases, limiting the ability to assess whether penalties deter repeat violations. As a result, reported spill counts and volumes should be understood as a minimum estimate of actual pollution events.

Data Processing and Categorization

For purposes of this analysis, a "spill" is defined as any unauthorized release, discharge, escape, or disposal of oil, gas, produced water, or other substances associated with oil and gas operations, consistent with New Mexico law and OCD reporting rules. A single spill incident may involve multiple released materials, each recorded as a separate entry in the state's spill database.

Spill records were categorized and analyzed across multiple dimensions to assess patterns and impacts over time. Spills were further analyzed using the Oil Conservation Division's standardized cause categories, as well as by operator, county, and land ownership, where these data fields were provided.

Spills were classified as gaseous or liquid based on the reported material. Reported spill volumes were aggregated by quarter and by material type. For liquid spills, both total volume spilled and volume lost (unrecovered) were analyzed where data were provided.

Spill Databases and Data Structure

Sorting state oil and gas spill data to calculate accurate totals is more complex than it may appear. Spill records cannot be reliably analyzed using a single search field because spill incidents often involve multiple materials and are categorized inconsistently across reporting fields. For example, searching 2025 data for "produced water release" under incident type yields 914 results, while searching the same dataset for "produced water" under material yields 925 results, reflecting differences in reporting structure rather than actual differences in pollution events.

Spill records are publicly available through two separate OCD databases, each serving a distinct function: The Incident Search lists spill events by time and location and may include multiple materials released during a single incident. The Spill Search lists each material released during a spill as a separate entry, along with the reported volume of that material.

For example, spill Incident Number nAPP2534942335 appears once in the Incident Search for a November 27, 2025 spill at Occidental Permian's South Hobbs Unit CTB. But this same spill appears twice in the Spill Search: once for 81 MCF of carbon dioxide and once for 20 MCF of natural gas (methane) released during the same incident. As a result, Incident Search data are best suited for counting spill events, while Spill Search data are necessary to calculate total volumes of individual pollutants.

In 2025, OCD began migrating all spill material and volume data into the Incident Search database in an effort to consolidate reporting into a single platform.[44] However, spill volumes reported in the new Incident Search do not always match volumes originally reported in the Spill Search. Due to these discrepancies, this report relies on the original Spill Search records to calculate total volumes of spilled materials and the quantity of spills per material for 2025.

Treatment of Missing and Incomplete Data

Spill analysis is complicated by reporting categories such as "other," "release other," "unknown," and blank fields, which obscure both the nature and extent of pollution.[45] Rather than excluding these records, the authors included and explicitly identified them as data gaps, recognizing that excluding uncertain records would further understate pollution and bias results.

Spill counts in this report were calculated using a consistent sorting sequence designed to maximize accuracy while preserving transparency. Records were first sorted by unit of volume, then by material, and only then by incident type. This methodology was reviewed by staff at the Oil Conservation Division and reflects the most reliable approach available given the structure of the state's databases.

ENDNOTES

1 New Mexico Oil Conservation Division Spill Search, queried January 5, 2026 for all spills reported between January 1 and December 31, 2025: https://wwwapps.emnrd.nm.gov/ocd/ocdpermitting/data/spills/Spills.aspx.

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10 Concerned Health Professionals of New York, Compendium of Scientific, Medical, and Media Findings Demonstrating Risks and Harms of Fracking and Associated Gas and Oil Infrastructure, Ninth Edition, October 19, 2023, https://concernedhealthny.org/compendium; see also Duke Study Finds A "Legacy of Radioactivity," Contamination from Thousands of Fracking Wastewater Spills, DeSmog Blog, May 8, 2016, https://www.desmog.com/2016/05/08/duke-university-study-finds-legacy-radioactivity-water-and-soil-contaminated-thousands-fracking-wastewater-spills.

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13 Each spill is the release of a separate pollutant, and multiple pollutants can be spilled during a single event. The state provides public access to spill data via a Spill Search and an Incident Search. The Spill Search used for this report lists all pollutants released during an incident or event as individual spills, which better quantifies overall potential impact.

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21 New Mexico Oil Conservation Division Spill Search, queried January 5, 2026 for all spills reported between January 1 and December 31, 2025: https://wwwapps.emnrd.nm.gov/ocd/ocdpermitting/data/spills/Spills.aspx.

22 Flare and vent releases unrecovered or "zero" in the spill data.

23 Climate equivalency calculation: NM oil and gas operators reported releasing 9,219,554 thousand cubic feet (MCF) of gaseous pollutants in 2025, predominantly methane (CH_4), according to the NM Oil Conservation Division Spill and Incident Databases. One thousand cubic feet of methane has a mass of approximately 20.3 kilograms, or 0.0203 metric tons, based on U.S. EIA physical property data. Using the U.S. EPA 100-year global warming potential (GWP) of 28 for methane, each MCF released is equivalent to 0.57 metric tons of carbon dioxide-equivalent (CO_2e) ($0.0203 \times 28 = 0.5684$). Multiplying this factor by the total reported gas releases yields approximately 5.24 million metric tons of CO_2e (9,219,554 MCF × 0.5684 tCO_2e/MCF). The U.S. EPA estimates that an average gasoline-powered passenger vehicle emits 4.6 metric tons of CO_2 per year, resulting in a climate impact equivalent to approximately 1.1 million passenger vehicles driven for one year (5,240,000 ÷ 4.6 ≈ 1,139,000). Sources: U.S. EIA, Natural Gas Monthly, https://www.eia.gov/naturalgas/monthly/pdf/ngm_all.pdf; U.S. EPA, Understanding Global Warming Potentials, https://www.epa.gov/ghgemissions/understanding-global-warming-potentials; U.S. EPA, Greenhouse Gas Emissions from a Typical Passenger Vehicle, https://www.epa.gov/greenvehicles/greenhouse-gas-emissions-typical-passenger-vehicle.

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25 Standard oilfield water tanker capacity assumed at 5,000 gallons. 9,446,051 ÷ 5,000 ≈ 1,889 tanker trucks spilled and 3,515,880 gallons ÷ 5,000 gallons per truck = 703.18 trucks lost to the environment.

26 Convoy length assumes ~60 feet per truck in a tight bumper-to-bumper lineup: 1,900 × 60 ÷ 5,280 = 21.6 miles (≈22 miles).

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29 Cloelle Danforth et al., An integrative method for identification and prioritization of constituents of concern in produced water from onshore oil and gas extraction, Environment International, Volume 134, January 2020, 105280, https://doi.org/10.1016/j.envint.2019.105280.

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31 Gaseous air pollutants are categorized as the following materials in the spill data: carbon dioxide, natural gas (methane) flared, natural gas (methane) vented, other, and "unknown". Liquid pollutants are categorized as the following in the spill data: chemicals, condensate, crude oil, diesel, drilling fluid/mud, gasoline, glycol, lube oil, motor oil, natural gas liquids, other, produced water, sulfuric acid, and "unknown".

32 Rankings are based on operator self-reported spill data submitted to the Oil Conservation Division and reflect reported spill counts, not production volume or facility count. The following operators have multiple legal names within the spill data and have been combined as follows: COG includes COG Operating and COG Production; Avant Operating includes Avant Operating I and Avant Operating II; OXY includes OXY USA and Occidental Permian; Cotera Energy includes Cotera Energy Operating, Cotera Energy Operating E, and Cotera Energy Operating F.

33 OCD civil penalty authority reinstated NMSA 1978, § 70-2-31(B); see February 25, 2020 press release, "Rule authorizing Oil Conservation Division to assess civil penalties for Oil and Gas Act violations is now in effect" accessed online January 17, 2025, https://www.emnrd.nm.gov/wp-content/uploads/sites/6/OCDPenaltiesRuleFinalizedFebruary252020_000.pdf.

34 Civil penalty limits and escalation criteria 19.15.5.10(D) NMAC.

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37 New Mexico Legislative Finance Committee Policy Spotlight: Orphaned Wells, New Mexico State Legislature, June 24, 2025: https://www.nmlegis.gov/Entity/LFC/Documents/Program_Evaluation_Reports/LFC%20Policy%20Spotlight%20-%20Orphaned%20Wells%20-%20Final.pdf.

38 Oil and Gas Act and spill reporting and response rules NMSA 1978, § 70-2-12(B); 19.15.29 NMAC.

39 Soil cleanup requirements for oil and gas releases 19.15.30 NMAC.

40 Water Quality Control Commission standards NMSA 1978, § 74-6-4; 20.6.4 NMAC; 20.6.2 NMAC.

41 Alternative abatement standards 19.15.30.9 NMAC.

42 New Mexico Oil Conservation Division (OCD), Incident Search database, Energy, Minerals and Natural Resources Department, available at https://wwwapps.emnrd.nm.gov/ocd/ocdpermitting/data/incidents/Incidents.aspx and New Mexico Oil Conservation Division (OCD), Spill Search database, Energy, Minerals and Natural Resources Department, available at https://wwwapps.emnrd.nm.gov/ocd/ocdpermitting/data/spills/spills.aspx.

43 WildEarth Guardians, 2025 Oil and Gas Spill Dataset, consolidated spreadsheet of OCD spill records, on file with authors and available upon request.

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45 "Other" is a category that does not define the cause, therefore the cause is unknown as listed in the Spill and Incident Searches. A precise cause may be listed in individual spill records on file with the Oil Conservation Division.

ENDORSEMENTS

TEWA WOMEN UNITED

FRACK OFF GREATER CHACO

Southwest Native Cultures

TORREON COMMUNITY ALLIANCE

CCFF CITIZENS CARING FOR THE FUTURE

YUCCA

OILFIELD WITNESS

NM NO FALSE SOLUTIONS nofalsesolutions.com

NM CLIMATE JUSTICE

EARTH CARE YOUTH LEADERSHIP FOR COMMUNITY CHANGE

Chaco Alliance

NEW MEXICO WATER ADVOCATES

new energy economy Addressing the Climate Challenge With Bold Solutions

RIO ARRIBA CONCERNED CITIZENS

Central PDA New Mexico

HEALTHY CLIMATE NEW MEXICO Health Professionals for Climate Action

Earth Ethics www.earthethics.us

Social Eco Education

EARTHWORKS

RENEWABLE TAOS

WildEarth Guardians

Exhibit 7

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ıardians

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Current work in wildlife, rivers, public lands, and climate

Press Releases

Q2 Waste Watch: New Mexico Oil and Gas Spill Counts Drop, but Toxic Waste Volumes Surge

New analysis from WildEarth Guardians shows "produced water" accounted for 96% of liquid spill volume in Q2, doubling volumes of waste spilled from previous quarter

DATE

July 14, 2026

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SANTA FE, *N.M.* – New Mexico recorded fewer oil and gas spills in Q2 2026 than in Q1, but the volume of toxic liquid waste released into the environment more than doubled, according to new analysis of industry-reported state data released today by WildEarth Guardians.

Operators reported 8,358 oil and gas spills from April through June, including 367 liquid spills that released more than 3.1 million gallons of toxic liquid waste. Nearly 1 million gallons were permanently "lost" to soil and water.

The findings build on WildEarth Guardians' Q1 Waste Watch analysis, which documented more than 9,000 spills in the first three months of the year, and the organization's 2025 New Mexico Oil and Gas Spill Report, which documented more than 38,000 spills statewide last year.

Together, the first half of 2026 shows the scale of the problem: **17,373 oil and gas spills in 181 days**, averaging **96 spills per day**, or one reported spill roughly every **15 minutes**. So far this year, operators have reported spilling more than **4.5 million gallons** of liquid oil and gas waste, with more than **1.5 million gallons** "lost", polluting soil and water.

"Once again, spill counts went down while damage went up,"

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said Melissa Troutman, Climate and Health Advocate at WildEarth Guardians. "Fewer incidents are causing larger, more severe pollution problems."

From Q1 to Q2, total reported spills declined by about **7%**, while the volume of liquid waste spilled increased by **124%**. Produced water spill volumes increased even more sharply, rising **148%** from Q1 to Q2.

"Produced water" is industry's euphemism for the toxic liquid waste brought to the surface during oil and gas extraction, often contaminated with salts, heavy metals, hydrocarbons, radioactive materials, and undisclosed drilling chemicals. In the Permian Basin, oil and gas operations generate far more waste than oil, with industry experts estimating four to five barrels of waste for every barrel of oil produced. Now, the industry is trying to rebrand that waste as a commodity, pushing proposals to treat, reuse, and discharge produced water even as state data show the existing produced water system is already spilling. The waste is even being pitched as a solution for data centers.

Operators reported spilling nearly **3 million gallons** of produced water in just three months in New Mexico, with more than **922,000 gallons** lost to soil and water. That means produced water made up a slightly smaller share of liquid spill incidents than in Q1, but a much larger share of the damage.

"Produced water is not just part of the spill problem in New Mexico. It is overwhelmingly driving the damage," said Troutman. "By Q2, virtually all liquids spilled were produced water, and nearly all of the toxic waste that polluted the environment was produced water."

The surge was driven in large part by a catastrophic June 9 spill by Occidental Permian Ltd. in Lea County. According to state data, the company released more than 2 million gallons of produced water, with nearly 589,000 gallons lost to the environment. The spill damaged 5.3 acres on private land.

That single incident accounted for **roughly two-thirds** of all liquid waste spilled in Q2 and more than **60%** of all liquid waste lost.

"One catastrophic produced water spill can erase any claimed progress in spill counts," said Rebecca Sobel, Climate and Health Program Director at WildEarth Guardians. "This is exactly why regulators should not treat falling incident numbers as proof that the system is working."

The volume of Q2 liquid waste spilled would fill about **624 standard oilfield tanker trucks**. In the first half of 2026, operators spilled enough waste to fill about **900 standard oilfield tanker trucks.** Parked bumper-to-bumper, that convoy would stretch more than **10 miles**. More than **315 tanker trucks' worth** of liquid oil and gas waste was

Received by OCD: 08/03/2026

permanently lost to New Mexico's land and water in just the first six months of 2026.

State data show produced water spills are overwhelmingly caused by predictable, preventable failures. In Q2, the leading causes of produced water spills were:

- **Equipment failure:** 109 incidents
- **Corrosion:** 57 incidents
- **Routine or "normal operations":** 28 incidents

Together, those three causes accounted for more than **83%** of produced water spills.

Impact by Region

Spill activity remains overwhelmingly concentrated in southeastern New Mexico. **Lea and Eddy counties accounted for 98% of all reported Q2 spills**, keeping the Permian Basin at the center of New Mexico's oil and gas pollution crisis.

But water impacts were not limited to the Permian. The spill database identified **16 water resource impacts in Q2**, including **12 waterway impacts** and **4 groundwater impacts**. The waterway impacts were concentrated outside the Permian, with **6 in San Juan County** and **3 in Sandoval County**, along with one each in Harding, Lea, and Eddy counties. Produced water was involved in most of the

Received by OCD: 08/03/2026

waterway impacts, underscoring that oilfield waste spills are threatening water resources beyond southeastern New Mexico.

Public and Tribal Lands Bear Worst Impacts

Public and Tribal lands also remain heavily impacted. Roughly **78% of liquid spill incidents** and **81% of produced water spill incidents** occurred on federal, state, Navajo, or Indian lease categories, even though the largest single-volume event occurred on private land.

Repeat Offenders

The same operators continue to dominate spill counts. In Q2, **EOG Resources Inc.** remained the top reported spiller by incident count, with **1,461 spills**. The top five operators by incident count, EOG Resources, XTO Permian Operating, Matador Production Company, Longfellow Energy, and Coterra Energy, were responsible for **4,606 spills**, or **55% of all Q2 incidents**.

But spill counts alone hide the worst damage. By volume, Occidental Permian Ltd. drove the Q2 toxic waste surge, with one major produced water release accounting for roughly two-thirds of all liquid waste spilled last quarter.

“New Mexico cannot manage this crisis by counting spills alone,” said Sobel. “The real measure is how much toxic waste

Received by OCD: 08/03/2026

is released, how much is recovered, who is repeatedly spilling, and whether regulators are enforcing the law."

Fracking Waste Processing Drives Spills

The Q2 findings also undercut industry claims that expanded produced water treatment, recycling, and reuse will solve New Mexico's oilfield waste crisis. Current spill data show the existing produced water management system is already failing, with major spills occurring across storage, transport, injection, and pipeline infrastructure.

"Industry keeps arguing that New Mexico needs more ways to move, treat, reuse, and commodify its fracking waste," said Sobel. "But the data show the state is already failing to safely contain this waste before any expansion. More infrastructure does not solve the problem if the system itself is spilling."

Despite tens of thousands of oil and gas spills reported each year, enforcement remains limited relative to the scale of pollution. Guardians' 2025 New Mexico Oil and Gas Spill Report found that the same companies repeatedly rank among the top spillers, while penalties remain rare.

"The public is being asked to accept routine contamination while industry asks for more permits, more reuse, and more ways to move its waste around New Mexico," said Sobel. "That is backwards. Before the state expands produced water reuse or discharge, regulators should require full chemical disclosure, proven treatment, enforceable liability, and real penalties for spills."

The Q2 data confirm that oil and gas spilling in New Mexico is not declining in any meaningful sense. It is becoming more concentrated, more toxic, and more damaging when systems fail.

"This is not an accident," said Sobel. "When companies spill this much waste, this often, and face so little consequence, the state is not just failing to stop the problem. It is allowing it."

The Q2 analysis also comes as the New Mexico Oil Conservation Division transitions from maintaining separate spill and incident databases to a single reporting system. While that change may improve access over time, it also creates a risk that future reporting will not be directly comparable to past quarters unless the state clearly explains how records are categorized, migrated, and counted. Already, spill and incident database pulls appear to show different counts for water pollution, including groundwater impacts. WildEarth Guardians will continue tracking the data to ensure database changes track the true scale of oil and gas pollution.

Background:

Q1 Waste Watch